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January 22, 2021

Via Electronic Filing

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, SC 29210

Re: Dominion Energy South Carolina, Incorporated Establishment of a Solar Choice Tariff Pursuant to S.C. Code Ann. Section 58-40-20
Docket Number 2020-229-E

Dear Ms. Boyd:

Please find attached for electronic filing the *Direct Testimony of R. Thomas Beach* on behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Vote Solar, Solar Energy Industries Association, and North Carolina Sustainable Energy Association in the above-referenced docket.

Please contact me if you have any questions concerning this filing.

Sincerely,

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STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of: Dominion Energy South Carolina, Incorporated's Establishment of a Solar Choice Metering Tariff Pursuant to S.C. Code Ann. Section 58-40-20	)))))))	**DOCKET NO. 2020-229-E**

DIRECT TESTIMONY AND EXHIBITS OF

R. THOMAS BEACH

ON BEHALF OF

THE SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, SOUTHERN ALLIANCE FOR CLEAN ENERGY, UPSTATE FOREVER, VOTE SOLAR, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, and THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

January 22, 2021

TABLE OF CONTENTS

EXHIBITS

I. <u>Introduction and Qualifications</u>

Q: PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: PLEASE DESCRIBE YOUR EXPERIENCE AND QUALIFICATIONS.

A: My experience and qualifications are described in the attached *curriculum vitae* (CV), which is **Exhibit RTB-1** to this testimony. As reflected in my CV, I have more than 35 years of experience on resource planning, rate design, and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the California Public Utility Commission ("CPUC"), working on the implementation of the Public Utilities Regulatory Policies Act, on the restructuring of California's natural gas industry, and as an advisor to three commissioners. Since leaving the CPUC in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted comments, studies, or reports on numerous occasions before the state energy regulatory commissions in many states. My CV includes a list of the formal testimony that I have sponsored in state regulatory proceedings concerning electric and gas utilities.

Q: PLEASE DESCRIBE MORE SPECIFICALLY YOUR EXPERIENCE ON AVOIDED COSTS AND ISSUES RELATED TO NET ENERGY METERING AND THE COST-EFFECTIVENESS OF RENEWABLE DISTRIBUTED GENERATION AND OTHER TYPES OF DISTRIBUTED ENERGY RESOURCES.

A: I have worked on issues concerning the calculation of avoided cost prices throughout my career, including sponsoring testimony on avoided cost issues in state regulatory proceedings in Oregon, California, Idaho, Montana, Nevada, New Hampshire, North Carolina, and Vermont. With respect to benefit-cost issues concerning renewable distributed generation (DG) and distributed energy resources (DERs), I have sponsored testimony on net energy metering (NEM) and solar economics in South Carolina and ten other states. Since 2013 I have co-authored benefit-cost studies of NEM or solar DG in Arkansas, Arizona, California, Colorado, New Hampshire, and North Carolina. I also co-authored the chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013 and is designed to provide policymakers with tools (including rate design changes) to address key questions concerning distributed generation resources.[1] Finally, since 2007, I have sponsored testimony on rate design issues concerning solar DG and DERs (such as electric vehicles and on-site storage) in general rate case proceedings in Arizona, California, Massachusetts, New Jersey, and Texas.

Q: HAVE YOU TESTIFIED BEFORE THIS COMMISSION?

A: Yes. I appeared before this Commission in December 2014, sponsoring testimony in Docket No. 2014-246-E recommending the methodology to use to evaluate NEM in South Carolina, pursuant to Act 236, the predecessor to Act 62. I sponsored testimony on behalf of The Alliance for Solar Choice. This

[1] This report has been published in *The Electricity Journal*, Volume 26, Issue 8 (October 2013). It is also available at http://americaspowerplan.com/.

proceeding resulted in Order No. 2015-194, which established the current NEM program.

I also sponsored direct and rebuttal testimony in October 2020 in Docket No. 2019-182-E, the proceeding to determine the methodology to be used to develop and assess the new Solar Choice tariffs to be implemented pursuant to Act 62. In particular, my rebuttal testimony presented a complete evaluation of Dominion Energy South Carolina's (Dominion or DESC) current NEM tariff using the methodology I proposed to use for the Solar Choice program. I submitted this testimony on behalf of the same parties that I am representing in this testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of South Carolina Coastal Conservation League, Upstate Forever, Southern Alliance for Clean Energy, Vote Solar, the Solar Energy Industries Association, and the North Carolina Sustainable Energy Association ("Joint Clean Energy Intervenors").

II. <u>Summary of Testimony</u>

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A: My testimony proposes a new residential Solar Choice tariff for DESC, consistent with Act 62. The key features of the Joint Clean Energy Solar Choice tariff ("Joint Solar Choice tariff") are:

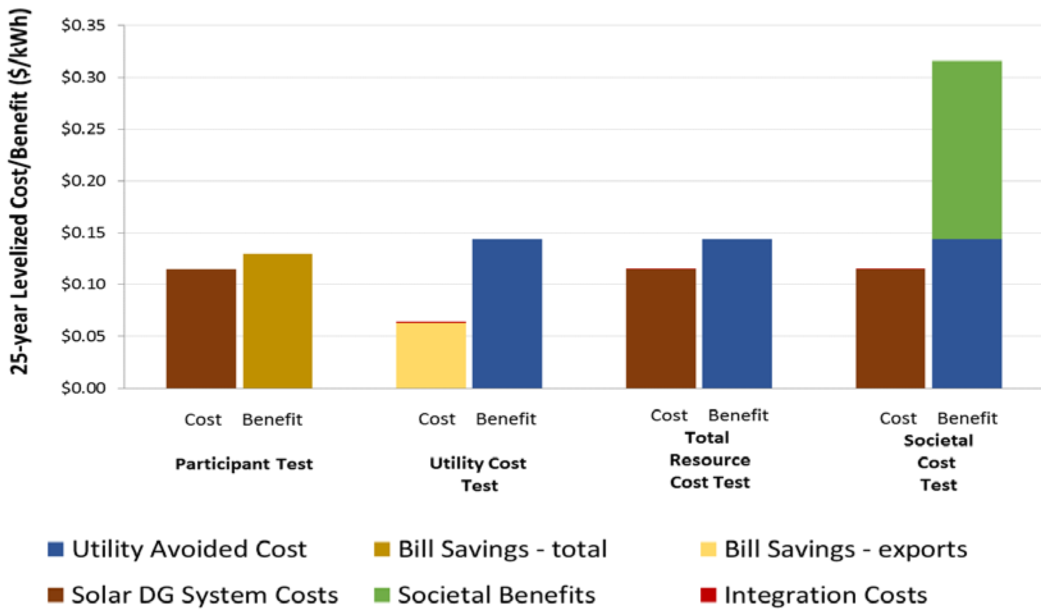
- *a requirement to take service on the Rate 5* ***time-of-use (TOU) rate****, once customers have access to adequate data to understand and to analyze the economics of installing solar under time-varying rates, and;*

- *a **minimum bill** that recovers the approved customer-related costs that do not vary with usage, to the extent that this amount exceeds the basic facilities charge (BFC) for Rate 5.*
- *a change to the **crediting provisions of the NEM tariff** for TOU rates to keep all excess on-peak kWh that are rolled over to subsequent months as credits only against subsequent on-peak consumption.*

This joint proposal will result in a small decrease in the bill savings available to typical residential customers who install solar. My cost-effectiveness testimony analyzing DESC's current NEM tariff, submitted in my rebuttal testimony in Docket No. 2019-182-E, showed that tariff to be cost-effective today, such that it is not strictly necessary to make changes to DESC's NEM tariff to comply with Act 62. Nonetheless, in the context of Act 62, it is important to implement a Solar Choice tariff that makes progress toward a rate design that can serve as a platform for customers to adopt multiple types of DERs and that aligns that tariff more closely with the utility's time-varying cost of service.

My testimony analyzes the proposed Joint Solar Choice tariff using the full set of standard benefit-cost tests that cover the perspectives of the major stakeholders in the deployment of distributed solar. Consistent with Act 62, this analysis considers a comprehensive list of benefits and costs and employs a long-term, life-cycle assessment that uses the long-run avoided costs for generation, transmission, and distribution that I developed for DESC in my prior testimony in Docket No. 2019-182-E. The results of the four principal cost-effectiveness tests are shown in **Figure ES-1**. The proposed Joint Solar Choice tariff passes all of the tests.

Figure ES-1: *Summary of Cost-Effectiveness Test Results for Joint Solar Choice Tariff*



Based on these cost-effectiveness results, I conclude that the proposed Joint Solar Choice tariff will not cause a cost shift to non-participating residential ratepayers, will benefit all DESC ratepayers, and in the long-run will reduce DESC's cost of service. The economics for customers who install solar under the new tariff are acceptable but not outstanding, such that I would expect further modest growth in distributed solar installations in DESC's service territory. This new clean resource will produce significant environmental and other societal benefits that I have quantified. Finally, the continued growth of solar DG will improve the reliability and resiliency of customers' electric service, enhance their freedom to choose the source of their energy supplies, access new sources of private capital to expand South Carolina's clean energy infrastructure, and provide an opportunity for the state's citizens to take advantage of federal tax incentives for solar.

The final section of the testimony is a critique of DESC's proposed Solar Choice tariff. The utility's proposed tariff includes a large monthly BFC, adds a subscription fee based on the size of the solar system, uses a solar-specific TOU rate design, and moves to the netting of imports and exports on a 15-minute basis. This tariff would result in a 55% reduction in the bill savings for a typical residential solar customer, such that a typical residential solar system would no longer be economic in DESC's service territory.

The DESC Solar Choice tariff is essentially a rate with a very large monthly fixed charge and lower TOU energy charges. Such a rate design rewards residential customers who use a lot of energy, either because they are wealthier or because they use energy inefficiently. Because the fixed monthly subscription fee increases as the solar system size increases, solar bill savings increase very little as the size of the customer's solar system increases. I show that the result of this structure is that the only residential solar systems that would be economic are small systems 3 kW or less in size installed by large residential customers, for whom the solar system would serve just 40% or less of their usage. Residential customers with lower usage would no longer have an economic opportunity to install solar on their more modest (or more energy efficient) homes. In fact, the DESC tariff would encourage wealthy and/or wasteful customers to game the utility's solar program by installing just a few panels to allow them to access a DESC Solar Choice rate that would provide them with major bill savings compared to the standard residential rate. This is not the result that Act 62 intended.

My testimony shows that the most problematic aspect of the design of DESC's proposed tariff is the utility's assumption that all transmission and distribution (T&D) costs allocated to residential customers are "fixed," such that they should be recovered through a fixed monthly subscription fee. I show that this is contrary to DESC's own cost of service study, and to the analysis of DESC's marginal/avoided T&D costs that I provided in Docket No. 2019-182-E. Residential solar systems will produce significant output to reduce the coincident and noncoincident peak loads that cause DESC to incur demand-related T&D costs.

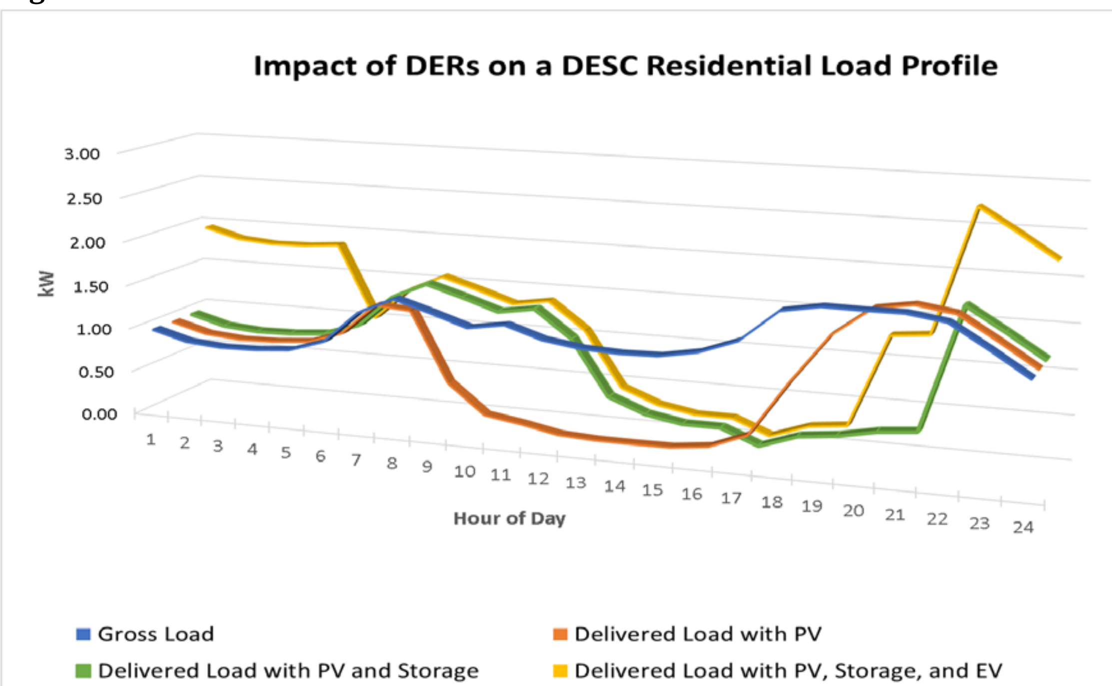
III. Proposed Joint Clean Energy Solar Choice Tariff

Q. IN THE CONTEXT OF ACT 62, WHAT DO YOU BELIEVE ARE THE KEY CONSIDERATIONS FOR THE DESIGN OF A NEW SOLAR CHOICE TARIFF?

A. The first consideration is that rooftop solar systems are just one type of distributed energy resource. DERs also include storage, smart thermostats, electric vehicles (EVs), and programmable heat pumps for space and water heating. Solar is a DER that produces on-site power over the daylight hours; other DERs such as storage, smart thermostats, and programmable appliances allow loads on the grid to be reduced or shifted in time. EVs and heat pumps are DERs that allow the utility to build new loads, with customers enabled and encouraged to use those technologies at times that do not stress the grid. In the coming future, customers increasingly will be able to use combinations of DERs in ways that will have significant impacts on the time profile of their energy use. **Figure 1** below shows four distinct residential load profiles that illustrate how a single DESC residential customer's load profile for delivered energy can change as the customer adopts three different DER technologies in succession. The four profiles are:

1. ***Blue:*** *Residential customer using 11,500 kWh per year with no DERs.*
2. ***Orange:*** *the customer adds solar with output equal to 75% of the annual load.*
3. ***Green:*** *customer adds 11 kWh of battery storage; storage is charged during solar production hours, and discharged in the 2 p.m. to 7 p.m. peak period.*
4. ***Yellow:*** *customer buys an EV using 3,500 kWh per year. EV is charged between 7 p.m. and 5 a.m.*

Figure 1



The second consideration is that many utility costs vary significantly by the time of day. As a result, time-of-use (TOU) rates are more accurate and more cost-based. The importance of time-varying pricing is increasing as a result of the growing use of DERs that enable customers to shift the time profile of their electric use. Finally, the wider availability of sophisticated metering is enabling TOU pricing for all types of customers. It is my understanding that DESC is in the process of rolling out an advanced metering infrastructure in its service territory, with all customers scheduled to have meters capable of TOU pricing by the end of 2022. Section 58-27-845(D) of Act 62 underlines the importance of providing customers with time-varying rates:

> For each class of service, the commission must ensure that each electrical utility offers to each class of service a minimum of one reasonable rate option that aligns the customer's ability to achieve bill savings with long-term reductions in the overall cost the electrical utility will incur in providing electric service, including, but not limited to, time-variant pricing structures.

Thus, particularly in the context of Act 62, the use of TOU rates by customers who adopt solar and other types of DERs is important in order to realize the full benefits of these new technologies, to increase the accuracy of pricing the services that utilities provide from the grid, and to minimize the potential for DERs to shift costs to other customers. In my opinion, the provision in Act 62 to consider the "cost of service implications" of DER customers directs the Commission to encourage the use of more accurate, time-varying rates by DER customers.[2] States with high penetrations of DERs – Hawaii, California, and Arizona, for example – have strongly encouraged or required solar customers to use TOU rates.[3] Solar has proven to be an important tool that encourages customers to learn about and to adopt TOU rates, and then to invest in DER technologies that change the profile of their energy use from the grid in ways that

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2 See Section 58-40-20(D)(2).

3 See, for example, California Public Utilities Commission Decision No. 16-01-044 adopting revisions to NEM in California, including a requirement to use TOU rates.

benefit both themselves and the system as a whole. That said, customers cannot understand the implications of TOU rates unless they have access to data on their electric load profile. DERs often involve significant long-term financial investments by customers. In order for customers to understand and to evaluate such investments, they need to have granular data on their time-varying energy use over the course of the year. It is my understanding that DESC expects to complete the roll-out of its advanced metering infrastructure (AMI) by approximately the end of 2022, and that, at some unstated point in time, the AMI deployment will include allowing customers to access their granular smart meter data.[4]

The third consideration is to address directly any issue of equity between participating and non-participating ratepayers. Section 58-40-20(G)(1) of Act 62 provides that the new Solar Choice tariff should "eliminate any cost shift to the greatest extent practicable on customers who do not have customer sited generation while also ensuring access to customer generator options for customers who choose to enroll in customer generator programs." For example, a minimum bill that covers the utility's customer-related costs that do not vary with usage can ensure that all customers, including solar customers, make this minimum contribution to the utility infrastructure that serves them. This is consistent with cost causation so long as the minimum bill is limited to the utility's customer-related costs for metering, billing, and customer account

[4] See DESC response to Vote Solar Data Requests (DR) 1-8 and 1-9. Act 62 requires that this data be made available to customers "to the extent such is readily available." See Section 58-27-845(E).

services that are independent of usage and which are incurred solely as a result of the customer's connection to the utility's distribution grid.

Finally, Section 58-40-20(G)(2) of Act 62 specifies that the new Solar Choice tariff should "permit solar choice customer generators to use customer generated energy behind the meter without penalty." Solar customers use a portion, typically about one-half, of their solar output to serve their own load behind the meter. This power never touches the utility system and reduces the customer's consumption from the grid in the same way that customers may reduce their usage through other types of DERs, such as installing more efficient appliances. Solar customers should not be penalized for this reduced usage by analyses such as the Ratepayer Impact Measure (RIM) test, which imputes to customers all of the usage that they might have consumed in the absence of installing solar. The RIM test is not used in South Carolina for other types of DERs, such as energy efficiency and demand response, which also reduce usage. When customers use more electricity than expected – for example, if they buy an EV – we charge them more; the new electric consumption above their past usage is not free. By the same token, customers who reduce their usage from the grid, for whatever reason, should not be charged for what they might have been expected to use based on their past consumption history.

Accordingly, to be consistent with Act 62's requirement not to penalize changes in solar customer's consumption from the grid, equity between participating and non-participating ratepayers should focus, first, on the compensation provided to solar customers for their exports to the grid, and, second, on expanding access to DER technologies to all DESC ratepayers. All customers should have an opportunity to invest in DERs such as solar in a way that allows participants to achieve bill savings while at the same time making the system run more economically, protecting all ratepayers from rising utility costs. This is an explicit goal of Act 62.[5]

Q: PLEASE SUMMARIZE YOUR JOINT SOLAR CHOICE PROPOSAL, BASED ON THESE CONSIDERATIONS.

A: The key features of my Joint Solar Choice proposal for residential customers are:

- *A requirement to take service under the Rate 5 TOU rate. The use of the TOU rate will provide a more accurate and cost-based rate, as well as a platform for additional DERs that a solar customer may adopt – including applications such as EVs and electric heat pumps that can grow DESC's overall loads.*
- *A **minimum bill** based on the residential class costs that are properly classified as customer-related. The level of the minimum bill should be limited to those costs that vary with the number of customers and that are independent of usage, such as the costs for the service drop, metering, billing, and customer service. Because the issue of the proper classification of customer-related costs is being contested in the utility's ongoing rate case, it is difficult to establish definitively the level of customer-related costs to use to set the minimum bill.[6] For the purposes of this testimony, I will use a placeholder of $13.50 per month, which is in the middle of the range of customer-related costs proposed in Docket No. 2020-125-E.[7] This minimum bill would cover the utility's customer-related costs that do not vary with usage, without inflating the BFC and thus reducing customers' incentive to conserve power.*
- *A change to the **crediting provisions of the NEM tariff** for TOU rates. The current tariff offsets excess on-peak kWh against less valuable off-peak kWh within the month. This undervalues on-peak output, which is unfair and will be an increasing problem as customers gain the ability to increase their on-peak output using storage and to reduce their on-peak consumption using other types*

[5] See Section 58-27-845(A) - (D).

[6] See Docket No. 2020-125-E, Direct Testimony of Allen W. Rooks on behalf of DESC, at p. 7; Rebuttal Testimony of Department of Consumer Affairs Dismukes (calculating a customer-related cost of $8.17 per residential customer when usage-related distribution plant costs are classified as demand-related)

[7] The customer-related costs proposed in Docket No. 2020-125-E range from the $8.17 per month proposed by Department of Consumer Affairs witness Dismukes to $19.48 per month proposed by DESC witness Rooks.

of DERs. I propose to keep all excess on-peak kWh that are rolled over to subsequent months as credits only against subsequent on-peak consumption. Similarly, all excess off-peak production in a month would be credited only against future off-peak usage. I am not proposing any changes to the cash-out provisions of the NEM tariff at the end of each year; these provisions encourage customers to size their solar production to no more than their annual usage.

Q: HOW DO THE BILL SAVINGS FOR YOUR PROPOSED JOINT SOLAR CHOICE RATE COMPARE TO CURRENT NET METERING UNDER ACT 236?

A: My proposed Joint Solar Choice rate would result in a modest reduction in bill savings of up to -8%, over a typical range of solar system sizes, compared to current net metering under Act 236. The following Table 1 shows the anticipated changes in bill savings from my proposed Joint Solar Choice tariff, compared to current NEM under the standard residential rate (Rate 8), for a range of customer and solar system sizes.

Table 1: *Change in Bill Savings from the Joint Solar Choice Tariff*

Solar Output as % of Usage	Customer Annual Usage *(kWh/year)*			
	7,000	10,000	13,000	16,000
90%	-8%	-6%	-5%	-4%
80%	-7%	-4%	-3%	-3%
70%	-3%	-1%	+1%	+1%

Q: DO YOU PROPOSE THAT THIS JOINT SOLAR CHOICE RATE WOULD BECOME EFFECTIVE ON JUNE 1, 2021?

A: I propose that the minimum bill would become effective on June 1, 2021. However, customers should not be required to use the Rate 5 TOU rate until they have access to at least one year of hourly load data from an AMI meter installed on their premises.[8] Until that time, solar customers should continue to be able to

[8] Section 58-27-845(E) of Act 62 ensures that customers have the right to obtain their usage data from the utility, and to share it with third-party providers, once it is available.

elect the standard tiered rate for a minimum of 10 years, with the addition of the minimum bill.

IV. Cost-Effectiveness of the Proposed Joint Solar Choice Rate

Q: HAVE YOU EVALUATED THE COST-EFFECTIVENESS OF YOUR PROPOSED JOINT SOLAR CHOICE RATE?

A: Yes, I have. I have used the cost-effectiveness methodology that I recommended and used in my direct and rebuttal testimony in Docket No. 2019-182-E. This methodology is based on the requirements of Act 62 and what I believe to be best practices for such an analysis. In my opinion, Act 62 makes clear that the Commission should adopt a benefit/cost methodology for net-metered DERs that has the following key attributes:

- ***Examine the benefits and costs from the multiple perspectives of the key stakeholders.*** *Cost effectiveness should be evaluated considering the perspectives of each of the major stakeholders: (1) the utility system as a whole, (2) participating solar customers, and (3) other ratepayers – so that the Commission can balance all of these important interests. Section 58-40-20(G) supports this approach by requiring that the benefit/cost methodology balance the often-competing interests of both participating and non-participating ratepayers. As a result, the Commission should consider the results of multiple cost-effectiveness tests – the Participant Cost Test (PCT) to gauge whether the adopted solar choice tariff is a reasonable opportunity for customers to adopt solar, the Utility Cost Test (UCT) to measure whether rates will increase for non-participants, and the Total Resource Cost (TRC) and Societal Tests to determine whether new solar resources provide a net benefit to the utility system (TRC Test) and society more broadly (Societal).*
- ***Consider a comprehensive list of benefits and costs****. Section 58-40-20(D) directs the Commission to consider the "the value of distributed energy resource generation according to the methodology approved by the commission in Commission Order No. 2015-194." That order established a comprehensive list of benefits of distributed generation. As set forth in my testimony in Docket No. 2019-182-E, all of these benefits can and should be quantified on a long-term basis. It is important to take a new look at all of these benefits, given Act 62's requirement that Solar Choice tariffs must consider the long-run marginal*

costs of all the utility's functional cost components – generation, transmission and distribution.[9]

- ***Use a long-term, life-cycle analysis.*** *The benefits and costs of DG should be calculated over a time frame that corresponds to the useful life of a DG system, which, for solar DG, is at least 25 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side. Section 58-40-20(D)(1) contemplates such a long-term analysis, by requiring the Commission to consider "the aggregate impact of customer-generators on the electrical utility's* <u>*long-run*</u> *marginal costs of generation, distribution, and transmission" (emphasis added).*

Q: PLEASE SUMMARIZE THE BENEFITS AND COSTS INCLUDED IN THE COST-EFFECTIVENESS TESTS THAT YOU HAVE USED.

A: **Table 2** below shows the benefits (+) and costs (–) used in the PCT, UCT, and the other common benefit-cost tests.

Table 2: *Demand-side Benefit (+) / Cost (–) Tests*

Perspective (Test)	**DER Ratepayer** (Participant or PCT)	**All Utility Ratepayers** (Utility Cost, or UCT)	**Non-Participating Ratepayers** (RIM)	**Resource Cost to Utility or Society** (TRC or Societal)
Capital and O&M Costs of the Distributed Energy Resource	–			–
Customer Bill Savings or Utility Lost Revenues	+		–	
Direct Benefits (Avoided Costs) -- Energy -- Generating Capacity -- T&D, including losses -- Avoided RPS compliance		+	+	+
Societal Benefits -- Reliability/Resiliency/Risk -- Environmental -- Economic				+ (Societal Only)
Federal Tax Benefits	+			+
Program Incentives	+	–	–	–
Program Administration & Integration Costs		–	–	–

[9] See Section 58-40-20(D)(1). As I discuss in Section V below, DESC has failed to calculate long-run marginal/avoided costs for its transmission and distribution functions.

Q: WHY SHOULD THE COMMISSION USE THE UCT RATHER THAN THE RIM TEST TO MEASURE IMPACTS ON NON-PARTICIPATING RATEPAYERS?

A: The UCT considers only the costs of DERs that are included directly in the utility revenue requirement. The RIM test, as applied to DERs such as energy efficiency and solar, typically includes all revenues that the utility could have realized if the customer did not install the DER, including revenues that the utility could have realized if the customer did not reduce or serve their own load behind the meter.

There are several reasons not to use the RIM test. First, the RIM test penalizes DER customers for the power that they use behind the meter on their own premises using their own private investments in DERs, contrary to Section 58-40-20(D)(2) of Act 62. It does so by essentially requiring DER customers to compensate other ratepayers for all of the impacts of their decision to reduce the amount of power they take from the grid. Other behind-the-meter consumption decisions – including decisions to use other types of DERs such as energy efficiency – are not so penalized. For example, we do not penalize a customer that simply uses less energy than they did the year before, or that installs a more efficient, unrebated appliance because the energy savings outweigh the higher costs. This is one reason why many states (including North and South Carolina) rely primarily on the UCT or TRC tests to evaluate the cost effectiveness of energy efficiency programs, rather than the RIM test.[10]

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[10] See Kushler, Nowak, & Witte, *A national survey of state policies and practices for the evaluation of ratepayer-funded energy efficiency programs* (February 2012), ACEEE Report Number U122. Available at https://www.aceee.org/sites/default/files/publications/researchreports/u122.pdf.

The RIM Test is also an incomplete metric of equity between participating and non-participating ratepayers that assumes that non-participants should be insulated completely from the technological change that DERs represent.[11] Other factors must be considered in balancing the equities between these groups of ratepayers. For example, any potential inequity revealed by the RIM test can be addressed by ensuring that all ratepayers have reasonable access to DERs or similar programs. The RIM test also should consider the societal benefits of DERs that are realized by all ratepayers/citizens, including non-participants.

Q: ARE THE AVOIDED COSTS THAT YOU HAVE USED IN YOUR COST-EFFECTIVENESS EVALUATION THE SAME AS PRESENTED IN YOUR REBUTTAL TESTIMONY IN DOCKET NO. 2019-182-E, WHICH EVALUATED DESC'S CURRENT NEM PROGRAM UNDER ACT 262?

A: Yes. These avoided costs are the principal benefits of solar in the UCT, TRC, and Societal tests. For the Commission's convenience, I include my rebuttal testimony from Docket No. 2019-182-E as **Exhibit RTB-2** to show the details on the avoided costs that I used to analyze the proposed Joint Solar Choice tariff.

Q: HAVE YOU REVISED THE BILL SAVINGS TO REFLECT YOUR JOINT SOLAR CHOICE PROPOSAL?

A: Yes. These savings are the primary benefit of solar for participating customers in the Participant Cost Test. The export credits that the utility provides to solar customers also are the principal cost in the UCT test.

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[11] Amory Lovins, founder of the Rocky Mountain Institute, said that the RIM test should be called the "Hardly Any Winners" test instead of a "No Losers" test because having to ensure that there are zero potential adverse impacts from a demand-side program means that few such programs will be implemented, even if the overall system benefits are significantly positive. *See The Electricity Journal* 33 (2020), at 106827.

I modeled residential bill savings under the Joint Solar Choice tariff proposed above, based on for DESC's Rate 5 TOU rate, a minimum bill of $13.50 per month, and the change I have proposed to the crediting of on-peak kWh. I have assumed the same residential load and solar generation that DESC witness Margot Everett used to design DESC's proposed Solar Choice tariff. Assuming a residential customer with an annual load of 13,544 kWh per year, and a solar system sized to serve 87% of that load (i.e. solar output of 11,823 kWh per year), I estimate monthly pre-solar costs of about $140 per month (on the tiered rate), dropping to monthly post-solar costs (on the Joint Solar Choice rate) of $32 per month, for bill savings of $109 per month. 49% of the total bill savings ($53 per month) are due to the power exported to the grid; these are the costs compensated by the utility, and I have used them as the costs in the UCT.

To determine a long-term levelized value for bill savings from exported power, I escalate the savings with inflation over a 25-year period, include the effect of solar degradation over time, and levelize the savings at an 8.5% discount rate. The bill savings for exported power are summarized in the final line of Table 3, in terms of $ per year, $ per month, and $ per kWh of total solar output.

Table 3: *Bill Savings for Proposed Residential Joint Solar Choice Tariff*

	$ / year	**$ / month**	**kWh**	**$ / kWh**
Pre-solar Bill	1,684	140	13,544	0.124
Post-solar Bill	380	32	1,721	0.221
Bill Savings - total	1,304	109		0.110
Onsite loads	671	56	11,823	0.057
Exports	633	53		0.054
25-year Level Bill Savings				
Total	1,475	123	11,363	0.130
Exports only	716	60		**0.063**

Q: PLEASE PRESENT THE COST-EFFECTIVENESS EVALUATION OF YOUR PROPOSED JOINT SOLAR CHOICE TARIFF.

A: As explained above, it is vital to examine the benefits and costs of distributed resources from multiple perspectives of each of the major stakeholders – the utility system as a whole, participating NEM/DER customers, and other ratepayers – so that the regulator can balance all of these important interests. Thus, the Commission should consider the results of the full suite of standard practice manual (SPM) tests for cost-effectiveness. I have assembled the benefits and costs of my proposed Joint Solar Choice tariff into the four primary SPM tests. The following **Figure 2** and **Table 4** show the results for the four SPM tests on the DESC system.

Figure 2: *Summary of Cost-Effectiveness Test Results for Joint Solar Choice Tariff*

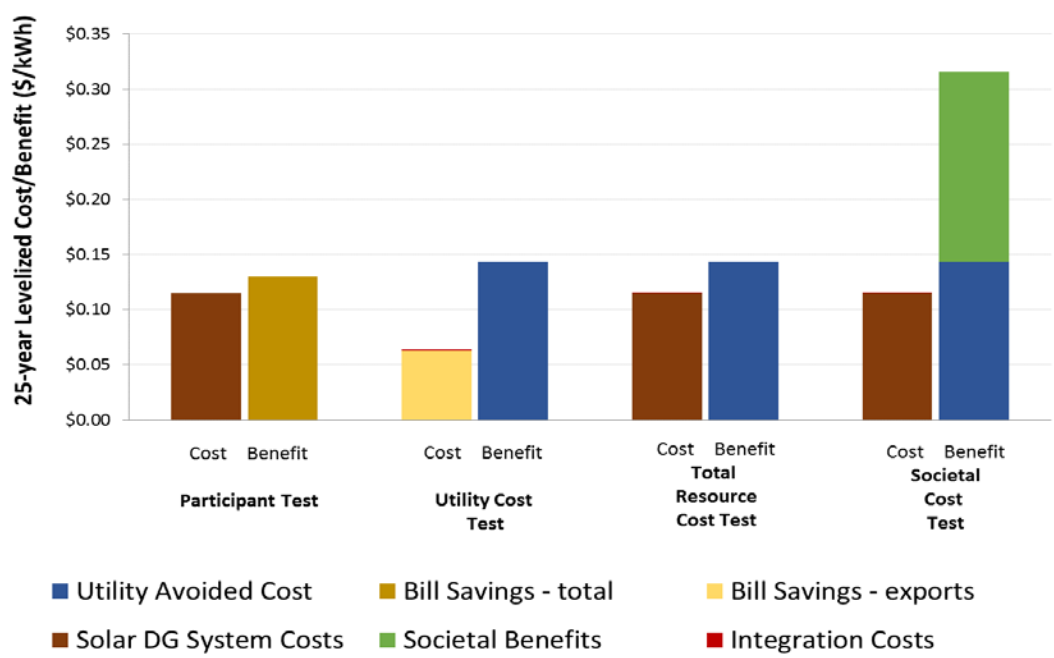

Table 4: *Benefits and Costs of Solar DG for DESC (25-yr levelized $/kWh)*

Benefit-Cost SPM Test	**Participant (PCT)**		**Utility Cost (UCT)**		**Total Resource (TRC)**		**Societal (SCT)**	
Category	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Direct Avoided Costs				0.144		0.144		0.144
Lost Revenues / Bill Savings		0.130 (all solar)	0.063 (exports)					
Integration			0.001		0.001		0.001	
Solar DG LCOE	0.115				0.115		0.115	
Societal Benefits								0.172
Totals	0.115	0.130	0.064	0.144	0.116	0.144	0.116	0.316
Benefit / Cost Ratios	**1.13**		**2.25**		**1.24**		**2.72**	

Q: WHAT DO YOU CONCLUDE FROM THESE RESULTS?

A: The results show that our proposed Joint Solar Choice tariff passes all of the SPM tests. As a result, my principal conclusions are the following:

1. Solar DG will continue to be a cost-effective resource for DESC under this Joint Solar Choice tariff, as the benefits equal or exceed the costs in the TRC, Utility Cost, and Societal tests. As a result, in the long-run, deployment of solar DG will reduce the utility's cost of service.

2. This Joint Solar Choice tariff does not cause an unreasonable cost shift to non-participating residential ratepayers, including low-income customers, as shown by the results for the Utility Cost test.

3. The economics of solar DG are marginal for DESC's residential customers, as shown by the Participant test results just above 1.0 and the modest amount of solar adoption to date. Equity for all ratepayers – including those who have not participated in the solar market to date – is best served by maintaining solar as a viable economic proposition for all ratepayers.

Accordingly, the Commission should adopt a Solar Choice tariff that makes gradual changes to the compensation provided to solar DG customers, such as the tariff proposed in this testimony.

4. There are significant, quantifiable societal benefits from solar DG, including public health improvements from reduced air pollution and from mitigating the damages from carbon emissions. These important benefits will accrue to all citizen-ratepayers, including non-participants.

5. Solar DG also provides other important benefits that are difficult to quantify. These include the enhanced reliability and resiliency of customers' electric service, enhanced customer freedom, new sources of private capital to expand South Carolina's clean energy infrastructure, and an opportunity for the state's citizens to take advantage of federal tax incentives for solar.

V. Critique of the DESC Solar Choice Tariff

Q: PLEASE DESCRIBE DESC'S PROPOSED SOLAR CHOICE TARIFF.

A: DESC's proposed residential Solar Choice tariff has the following key features:[12]

- ***A monthly BFC of $19.50****, based on the utility's decision to classify a significant portion of distribution plant costs as customer-related for the residential class, as DESC is recommending in Docket No. 2020-125-E.*
- *A monthly* ***Subscription Fee of $5.40 per kW-AC of installed solar capacity****, to recover the transmission and distribution costs allocated to residential customers, which DESC alleges are "fixed" and do not vary when a customer reduces its usage by installing solar. The minimum subscription fee will be $16.20 per month, based on a 3 kW system. DESC is proposing an even higher subscription rate of $6.50 per kW-AC for non-residential customers, with a minimum subscription size of 7.5 kW.*

[12] See DESC Testimony (Rooks), at pp. 5-7.

- ***New TOU periods**, with on-peak hours of 5:00 a.m. to 9:00 a.m. during winter months (December through February) and 4:00 p.m. to 8:00 p.m. during summer months (June through September).*
- *DESC is proposing TOU **energy charges** of $0.18417 per kWh for on-peak winter; $0.16749 per kWh for on-peak summer; and $0.06735 per kWh for all off-peak charges, to include weekends and holidays.*
- *DESC would measure both inflows and outflows of power on a 15-minute interval basis (in other words, **15-minute netting** of imports and exports).*

Q: WHAT IS THE FIRST ISSUE THAT CONCERNS YOU WITH DESC'S PROPOSED SOLAR CHOICE TARIFF?

A: The first issue of concern is that DESC's proposal would result in a major reduction in the bill savings available to a typical solar customer. A typical residential customer's savings from investing in solar would drop by one-half. We have calculated the annual average bill savings under DESC's proposed Solar Choice tariff, using the same representative solar customer that DESC witness Everett used to develop the DESC Solar Choice rate, and compared them to the bill savings under the current NEM program (on the tiered Rate 8) and our proposed Joint Solar Choice tariff. This comparison is shown in **Table 5** below.

Table 5: *Comparison of Residential Bill Savings*

Proposal	Bill Savings		% Change from Current NEM
	$/month	***$/kWh***	
Current NEM Tiered Rate	115	0.116	--
Joint Solar Choice	109	0.110	-5%
DESC Solar Choice	52	0.053	-55%

On a 25-year levelized basis, the DESC proposal would produce bill savings of $0.062 per kWh.[13] This compares to 25-year levelized solar costs of $0.094 per kWh for cash purchases and $0.115 per kWh for financed systems.[14] Thus, the

13 The 25-year levelized bill savings assume 2% annual escalation in rates, 0.5% annual degradation in solar output, and an 8.5% discount rate.

14 These solar costs are net of the tax benefits of the 26% federal tax credit (which the U.S. Congress recently extended through 2022) and the 25% state tax credit (capped at $3,500).

typical residential solar system would no longer be economic under DESC's proposed tariff.

Q: IS THERE A RELATIVELY SIMPLE WAY TO SHOW HOW DESC'S PROPOSAL WOULD UNDERMINE THE ECONOMICS OF RESIDENTIAL SOLAR?

A: Yes. The typical 7 kW-AC system which DESC used to develop its tariff would have an initial cost of $26,040. After the federal and state tax credits, the capital cost would be $12,910.[15] Given the monthly bill savings of just $52 under the DESC tariff, the simple payback on this system is over 20 years. That is not a reasonable investment. In comparison, the simple payback is 9.4 years under the current NEM program and 9.9 years under my Joint Solar Choice proposal[16] – short enough for continued investment in rooftop solar in Dominion's territory. In my experience, simple paybacks of this length (about 10 years) represent a reasonable, but not outstanding investment for residential customers, and are consistent with the moderate growth that has characterized the residential solar market in South Carolina under Act 236.

Q: HOW DO YOU SQUARE YOUR ANALYSIS WITH THE PRO FORMA MODEL OF DESC WITNESS SCOTT ROBINSON, WHOSE TESTIMONY APPEARS TO SHOW THAT THE BILL SAVINGS UNDER THE DESC TARIFF COVER RESIDENTIAL SOLAR COSTS?

A: Mr. Robinson's testimony is based on customers installing a small 3 kW-DC system whose output is only about one-third (32%) of the typical annual usage of

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The levelized costs also consider financing costs, ongoing costs for O&M, inverter replacement, and the customer's discount rate.

[15] For a system of this size, the state tax credit cannot be used completely in the first year. We discounted by 5% the portion of the state tax credit carried over to the second year.

[16] These paybacks use the monthly bill savings from **Table 5**.

residential solar customers.[17] This is far smaller than the 7 kW-AC system assumed by DESC's witness Everett, a system which serves 87% of the usage of the typical residential solar customer. In fact, the bill savings under the DESC tariff will be similar to the current NEM tariff only if customers install small systems of 3 kW-AC or smaller – basically, systems that cover no more than about 40% of the typical solar customer's usage. I have compared bill savings under the current NEM tariff to those under the DESC Solar Choice tariff, for a range of solar system sizes, again for the typical residential customer from witness Everett's testimony. The results of this analysis are shown in **Table 6**. The analysis shows that the bill savings under the DESC Solar Choice tariff will be significantly lower than under the current NEM tariff, unless the customer limits the solar system to a size that serves no more than about 40% of their load. This is far below the size of the typical Act 236 system, which serves 87% of the customer's load.

Table 6: *Change in Bill Savings – Current NEM to DESC Solar Choice*
Typical Solar Customer - 13,544 kWh per year electric usage

Solar Output as % of Customer Annual Usage	**System Size *(kW-AC)***	**Bill Savings *($/month)***		**% Change: Current NEM to DESC**
		Current NEM Tariff	**DESC Solar Choice**	
90%	7.1	117	52	-56%
87%	6.9	115	52	-55%
80%	6.3	105	52	-51%
70%	5.5	92	51	-44%
60%	4.8	79	51	-36%
50%	4.0	66	50	-24%
40%	3.2	53	49	-7%
32%	2.5	43	46	+7%
30%	2.4	40	45	+11%
20%	1.6	27	38	+42%
10%	0.8	13	30	+138%

[17] See DESC Testimony (Robinson), at p. 12.

Q: THE ANALYSIS IN TABLE 6 SHOWS THAT THE BILL SAVINGS UNDER THE DESC PROPOSED TARIFF ARE NOT SENSITIVE TO THE SIZE OF THE SYSTEM. WHY IS THAT?

A: The reason for this is that DESC's proposed monthly Subscription Charge of $5.40 per kW-AC largely offsets the additional bill savings from adding another 1 kW-AC of solar capacity. For example, for the system analyzed in Table 5 under DESC's proposed Solar Choice tariff, moving from a 4 kW to a 5 kW system increases bill savings by $6.11 per month, but this is mostly offset by the $5.40 per month increase in the subscription fee. Thus, under DESC's proposed tariff, the typical residential customer would have little incentive to install a system larger than about 3 kW-AC.

Q: TABLE 5 ALSO SHOWS SIGNIFICANT BILL SAVINGS UNDER THE DESC PROPOSAL EVEN IF A CUSTOMER ONLY INSTALLS A VERY SMALL SYSTEM. FOR EXAMPLE, A SYSTEM WITH JUST 0.8 KILOWATTS OF CAPACITY WOULD AMOUNT TO JUST A FEW PANELS, BUT SUCH A SYSTEM WOULD SAVE THE TYPICAL CUSTOMER $35 PER MONTH. WHY IS THAT THE CASE?

A: In essence, the DESC Solar Choice tariff is a rate with a large fixed charge – at least $35.90 per month for a 3 kW-AC system – and volumetric rates significantly lower than DESC's standard residential rates. Such a rate design produces substantial bill savings for large residential customers – presumably customers who are wealthier and live in larger homes or who are profligate in their energy use (or both). The bill savings available to large residential users from this inefficient rate design are far greater than the savings from installing solar. For example, if the customer modeled in Table 6 installs just a few panels (0.8 kW), the bill savings from the solar output will be just $7 per month, but the savings from switching to DESC's proposed Solar Choice rate will be $23 per month. The simple payback for such a token solar system would be about four years, with the large customer saving $360 per year, or $9,000 over the next 25 years. Thus, the proposed DESC tariff would encourage larger – and presumably wealthier and/or wasteful – residential customers to game the system to reduce their electric bills by installing a minimal solar system just to qualify for the more favorable rate. Even more troubling, DESC's proposal likewise benefits inefficient users of electricity, sending a price signal that undervalues both conservation and efficiency measures, contrary to the policy of South Carolina as set forth in Act 62. Under the Company's proposal, a large, inefficient user of electricity could save substantial money on their bills by installing a token rooftop solar PV system while at the same time continuing to put significant demands on the utility system.

The following **Table 7** is the same analysis, with similar results, for a very large residential customer using 16,000 kWh per year.

Table 7: *Change in Bill Savings – Current NEM to DESC Solar Choice*
Very Large Solar Customer - 16,000 kWh per year electric usage

Solar Output as % of Customer Annual Usage	**System Size *(kW-AC)***	**Bill Savings *($/month)***		**% Change: Current NEM to DESC**
		Current NEM Tariff	**DESC Solar Choice**	
90%	8.4	138	63	-54%
80%	7.5	125	63	-49%
70%	6.6	109	63	-43%
60%	5.6	94	62	-34%
50%	4.7	78	62	-22%
40%	3.7	63	60	-4%
30%	2.8	47	58	+22%
20%	1.9	31	50	+59%
10%	0.9	16	41	+162%

Q: WOULD THE DESC SOLAR CHOICE TARIFF BENEFIT SMALLER CUSTOMERS WHO MIGHT INSTALL A SMALL SOLAR SYSTEM?

A: No. **Table 8** below is the same analysis presented in Tables 5 and 6, except for a smaller customer with 7,000 kWh per year of electric use. For this small customer, the DESC tariff would produce far lower bill savings compared to current NEM, for all system sizes.

Table 8: *Change in Bill Savings – Current NEM to DESC Solar Choice*
Small Solar Customer - 7,000 kWh per year electric usage

Solar Output as % of Customer Annual Usage	System Size *(kW-AC)*	Bill Savings *($/month)* Current NEM Tariff	Bill Savings *($/month)* DESC Solar Choice	% Change: Current NEM to DESC
90%	3.7	60	21	-64%
80%	3.3	54	21	-60%
70%	2.9	47	21	-57%
60%	2.5	41	18	-55%
50%	2.0	34	16	-54%
40%	1.6	27	13	-52%
30%	1.2	20	10	-51%
20%	0.8	13	10	-52%
10%	0.4	7	3	-61%

Q: IN LIGHT OF THE ABOVE ANALYSIS, HOW WOULD YOU CHARACTERIZE THE DESC SOLAR CHOICE TARIFF PROPOSAL?

A: In essence, the DESC Solar Choice tariff proposal is a classic "McMansion rate" that will benefit only wealthier and/or wasteful customers who consume large amounts of electricity. This would limit the market for residential solar to large residential users who might install a minimal system in order to access a Solar Choice rate that is highly favorable for large and inefficient consumers. Dominion's proposal would erect an economic structure that would encourage the use of the state's solar program to game the utility's rate structure for the benefit of wealthier and less efficient customers.

Q: WOULD THIS RESULT BE CONTRARY TO ACT 62?

A: Yes, Act 62 first provides that the intent of the Solar Choice tariff is to "build upon the successful deployment of solar generating capacity through Act 236 of 2014 to continue enabling market driven, private investment in distributed energy resources across the State by reducing regulatory and administrative burdens to customer installation and utilization of onsite distributed energy resources."[18] DESC's proposed Solar Choice tariff would place unreasonable new limitations on the size of the solar systems that would be economic to deploy in DESC's service territory. If approved, this tariff would erect a new barrier to broad customer use of this clean energy technology, particularly by smaller residential customers.

The next section of Act 62 states that the Solar Choice tariffs should "avoid disruption to the growing market for customer scale distributed energy resources."[19] Dominion's proposal clearly would disrupt the solar market in its territory, by dramatically limiting the size of the residential solar systems that would be economic for customers to install.

Q: WITNESS EVERETT'S TESTIMONY DISCUSSES HOW DESC DESIGNED ITS SOLAR CHOICE RATE. WHICH ASPECTS OF THAT DESIGN DO YOU FIND TO BE PARTICULARLY PROBLEMATIC?

A: First, from a conceptual perspective, DESC has proposed a rate that would be specific to solar customers, without providing a standard cost-of-service analysis for the full range of customer-generators who would be subject to that rate. Instead, the utility has sought to "reverse engineer" a rate that, in essence, would

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[18] Section 58-40-20(A)(1).
[19] Section 58-40-20(A)(2).

ensure that a solar customer contributes the same amount of revenue to DESC that it paid before adding solar, except for a modest amount of avoided energy and generation capacity costs derived from the avoided cost pricing for large wholesale qualifying facilities (QFs).[20] As a result, the design of the DESC tariff does not look at the transmission and distribution costs that should be assigned to solar customers under cost causation principles, but instead assumes that all T&D costs allocated to residential customers are "fixed," such that they should be recovered through a fixed monthly subscription fee.

The design of the subscription fee as a fixed charge is inconsistent with DESC's own cost-of-service studies, and fails to comply with Act 62's directive to consider "the cost of service implications of customer generators on other customers within the same class."[21] In its pending general rate case, the utility recognizes transmission and most distribution costs as "demand-related," such that "customers cause the Company to incur these investments and expenses based on the relative demand requirements that they place upon the system."[22]

[20] See DESC Testimony (Everett), at pp. 27-47, esp. p. 29, describing the first step in her rate design process as "[d]etermined the revenue requirement that must be collected to ensure a 'revenue neutral' rate design that results in the average NEM customer paying the same amount annually as they would under their current rate, *prior to installing generation system*." (emphasis in original) For other types of DERs, the utility's approach would never be accepted. For example, consider a customer who buys an old drafty home and spends $15,000 on comprehensive upgrades to make it highly energy efficient. DESC's proposal here is akin to setting the tariff for that customer to recover what the company would have received in revenue before the customer made those upgrades.

[21] Section 58-40-20(D)(2).

[22] See Docket No. 2020-125-E, Direct Testimony of Kevin R. Kochems on behalf of DESC, at p. 14. Mr. Kochems also notes that demand-related costs can only be considered to be constant, and thus "fixed costs," in the short run. Rooftop solar obviously is a long-term resource with a 25-year life. Further, Act 62 clearly contemplates a long-term analysis, by requiring the Commission to consider "the aggregate impact of customer

The utility allocates transmission costs based on coincident peak usage in the 2 p.m. to 6 p.m. hours in the peak summer month (July).[23] The utility thus clearly recognizes that it incurs transmission costs based on customer's usage during these peak summer hours. There will be substantial solar output during these peak hours – the capacity factor of rooftop solar in DESC's service territory from 2 p.m. to 6 p.m. in July is 50%. As a result, the installation of rooftop solar will allow DESC to avoid transmission costs on a long-run basis, and transmission costs should not be considered to be invariant to the installation of customer-sited solar.

The utility's cost-of-service study supports the same conclusion for demand-related distribution costs. These costs are allocated based on a non-coincident peak (NCP) allocator that measures the relative contribution of each class's noncoincident peak demand.[24] Based on the residential load profile used by DESC witness Everett, the residential class's noncoincident peaks occur on winter mornings and late on summer afternoons. The hours of maximum residential demand are broadly consistent with the peak hours in DESC's existing TOU rate.

Solar also will contribute to reducing the residential NCP, although this contribution will be lower than for the system CP, due to the timing of the

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generators on the electrical utility's <u>long run</u> marginal costs of generation, distribution, and transmission" (emphasis added). See Section 58 40 20(D)(1).

[23] *Ibid*., at pp. 17-18: "The CP (coincident peak demand) allocator is developed based on the contribution of each customer class to the system territorial peak demand experienced during the test year. The Company's territorial peak demand usually occurs between the summer hours of 2 p.m. and 6 p.m.; therefore, the Company has historically used the average peak in this four-hour band."

[24] *Ibid*., at p. 18: "The NCP allocator is developed by taking the non-simultaneous peak demands of the different classes whenever they occurred during the test year."

residential class peaks. Based on witness Everett's residential load and solar profiles, the solar contribution to reducing loads in the top 10% of residential peak demand hours is 29% of the solar nameplate capacity. Again, like transmission, distribution costs should not be considered to be "fixed" costs that solar customers cannot avoid.

Finally, my rebuttal testimony in Docket No. 2019-182-E, at pages 10-11, includes a detailed analysis of solar's contribution to reducing the peak loads at DESC's transmission and distribution substations, based on hourly load data from those substations. Again, this analysis also shows that distributed solar will contribute significantly to reducing the peak demands on the DESC T&D systems that cause the utility to incur demand-related T&D costs over time.

Q: WHAT OTHER ASPECTS OF THE DESIGN OF THE DESC SOLAR CHOICE TARIFF CONCERN YOU?

A: I am also concerned with:

- *DESC's proposed use of a yet-to-be-approved $19.50 per month in customer-related costs. Only those actual customer-related costs that are approved in Docket No. 2020-125-E should be used for the minimum bill in the Solar Choice tariff. In my opinion, customer-related costs should be limited to the metering, service drop, billing, and customer service costs that are required to provide access to the grid and that depend on the number of customers.*
- *The Commission should not adopt DESC's proposed changes to TOU periods. DESC should use TOU periods consistent with its retail rates, so that TOU rates can be a platform for all types of DERs, not just solar. DESC's cost of service witness Kevin Kochems in the utility's pending rate case affirmed that the 2:00 p.m.to 6:00 p.m. summer peak period is when the company's coincident peak occurs.25*
- *Use of 15-minute netting is not necessary, because avoided costs, as demonstrated in Exhibit RTB-2, including avoided T&D, are comparable to the retail rate. As a result, it remains reasonable to use annual netting with the*

[25] See Docket No. 2020-125-E, Direct Testimony of Kevin R. Kochems on behalf of DESC, at pp. 17-18.

excess kWh from one month carried forward to offset usage in subsequent months.

VI. Conclusion

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

CERTIFICATE OF SERVICE

I hereby certify that the parties listed below have been served with a copy of the *Direct Testimony of R. Thomas Beach* filed on behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Vote Solar, Solar Energy Industries Association, and North Carolina Sustainable Energy Association by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

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This 22nd day of January, 2021.

s/ Katherine L. Mixson

R. THOMAS BEACH
Principal Consultant

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

    - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

    - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

    - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

    - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

    - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

- *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

- *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

- *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

- *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

- *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

- *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

- *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

- *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

- *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony on behalf of the **Joint Solar Parties** (R. 14-07-002 — September 30, 2015)

- *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

- *Selection of Time-of-Use periods, and rate design issues for solar customers.*

86. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 16-09-003 — April 28, 2017)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

87. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 17-06-030 — March 23, 2018)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

88. Prepared Direct and Rebuttal Testimony on behalf of **Calpine Corporation** (A. 17-11-009 – July 20 and August 20, 2018)

    - *Gas transportation rates for electric generators, gas storage and balancing issues*

89. Prepared Direct Testimony on behalf of **Gas Transmission Northwest LLC** and the **City of Palo Alto** (A. 17-11-009 – July 20, 2018)

    - *Rate design for intrastate backbone gas transportation rates*

90. Prepared Direct Testimony on behalf of **EVgo** (A. 18-11-003 – April 5, 2019)

    - *Electric rate design for commercial electric vehicle charging*

91. Prepared Direct and Rebuttal Testimony on behalf of **Vote Solar** and the **Solar Energy Industries Association** (R. 14-10-003 — October 7 and 21, 2019)

    - *Avoided cost issues for distributed energy resources*

92. Prepared Direct and Rebuttal Testimony on behalf of **EVgo** (A. 19-07-006 – January 13 and February 20, 2020)

    - *Electric rate design for commercial electric vehicle charging*

93. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 19-03-002 — March 17, 2020)

    - *Electric rate design issues for solar and storage customers*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

   - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

   - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).

4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

   - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

   - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
   b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

   - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of **Vote Solar** (Case No. U-18419—January 12, 2018)

2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

   - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

   - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

    - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

    - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

    - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

    - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

2. Direct Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018; Docket E-100 Sub 158; June 21, 2019)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910,01911, and 1912 — March 16, 2018).

   - *Resource value of solar resources in Oregon*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
   https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

   - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of: South Carolina Energy Freedom Act (H.3659) Proceeding Initiated Pursuant to S.C. Code Ann. Section 58-40-20(C): Generic Docket to (1) Investigate and Determine the Costs and Benefits of the Current Net Energy Metering Program and (2) Establish a Methodology for Calculating the Value of the Energy Produced by Customer-Generators	)	**DOCKET NO. 2019-182-E**

REBUTTAL TESTIMONY

R. THOMAS BEACH

ON BEHALF OF

THE SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, SOUTHERN ALLIANCE FOR CLEAN ENERGY, UPSTATE FOREVER, VOTE SOLAR, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, and THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

October 29, 2020

TABLE OF CONTENTS

I. INTRODUCTION

Q: PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A: Yes, on October 8, 2020, I submitted direct testimony on behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Vote Solar, the Solar Energy Industries Association, and the North Carolina Sustainable Energy Association. My experience and qualifications are presented in my CV, which is Exhibit RTB-1 to my direct testimony.

II. EXECUTIVE SUMMARY

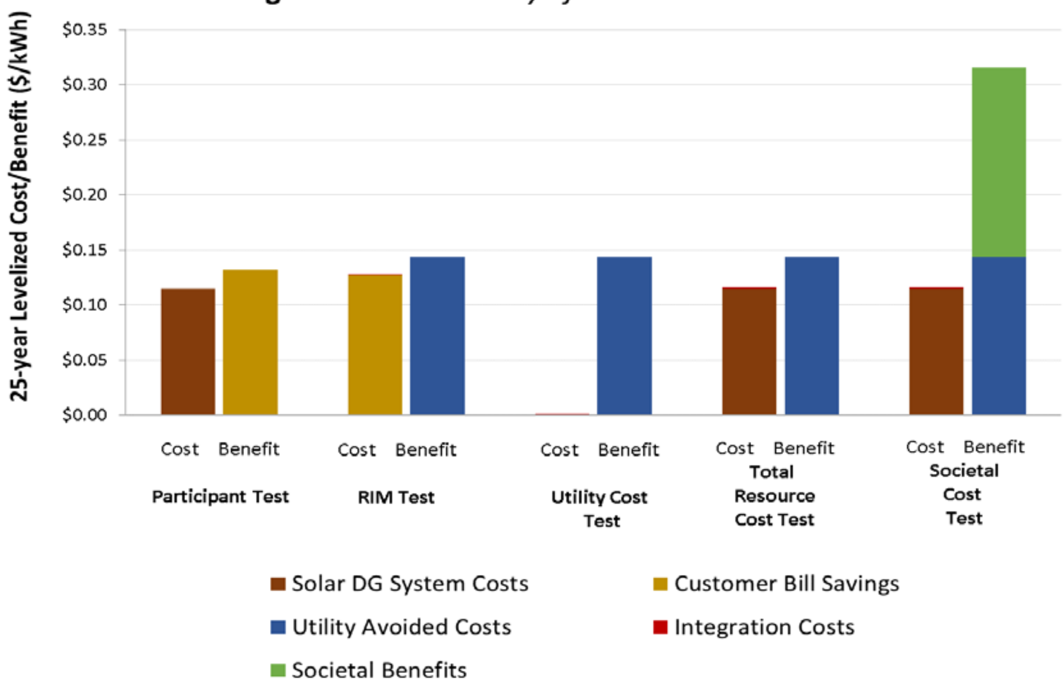
Q: PLEASE PRESENT A BRIEF SUMMARY OF YOUR REBUTTAL.

A: This rebuttal testimony focuses first on the benefit and cost numbers for residential solar presented in the testimony of Dominion Energy South Carolina (DESC or Dominion). DESC fails to consider and quantify all of the benefits and costs of DERs that the Commission adopted in Order No. 2015-194 and that Act 62 states should be considered in evaluating the upcoming Solar Choice tariffs. In some cases (such as avoided energy costs), the utility does not analyze the benefits over the full 25-year economic life of distributed solar resources. With respect to other quantifiable benefits (such as avoided capacity costs for transmission and distribution, avoided fuel hedging costs, and avoided costs to reduce carbon emissions), the utility testimony is silent.

In response, this rebuttal quantifies the full slate of the benefits and costs of distributed solar on the DESC system, revising many of DESC Witness Margot

Everett's numbers and providing several benefits that DESC does not recognize. I then apply the full set of Standard Practice Manual (SPM) cost-effectiveness tests to residential solar on the DESC system. The following **Figure ES-1** shows the results:

Figure ES-1: *Summary of SPM Test Results*



At this time, residential solar on the DESC system appears to pass all of the SPM cost-effectiveness tests. As a result, there is not presently a cost shift from solar customers to non-participating ratepayers, and distributed solar is a cost-effective resource for DESC ratepayers. There is also a small net benefit for customers who install solar, indicating that the market should continue to grow, albeit slowly, under the present net metering tariffs. Finally, there are significant, quantifiable societal benefits from distributed solar, including public health benefits from reduced air pollution and from mitigating the damages from carbon emissions.

I recommend that a similar analysis should be applied to the Solar Choice tariffs that DESC and the other South Carolina utilities may propose in future utility-specific proceedings pursuant to Act 62.

Finally, my testimony responds briefly to the opening testimony of the Office of Regulatory Staff (ORA) on a cost-of-service issue for the Duke Energy utilities and on the possible impacts of Solar Choice tariffs on low-income customers.

III. RESPONSE TO DOMINION ENERGY SOUTH CAROLINA

Q: PLEASE SUMMARIZE YOUR CONCERNS WITH DESC'S TESTIMONY ON THE METHODS TO BE USED TO DEVELOP SOLAR CHOICE TARIFFS PURSUANT TO ACT 62.

A. My direct testimony discusses the five key attributes of a benefit/cost methodology for net-metered distributed energy resources (DERs) that is consistent with Act 62. Two of these attributes are that the method should:

- consider a comprehensive list of benefits and costs and,
- use a long-term, life-cycle analysis.

As discussed below, the testimony of DESC witness Everett does not consider and quantify all of the benefits and costs of DERs and does not analyze them over the full 25-year economic life of the distributed solar resources that will be developed under the Solar Choice tariffs. This rebuttal presents my own calculation of the benefits and costs of distributed solar today on the DESC system; I revise many of DESC Witness Everett's numbers and supply several benefits that DESC does not recognize.

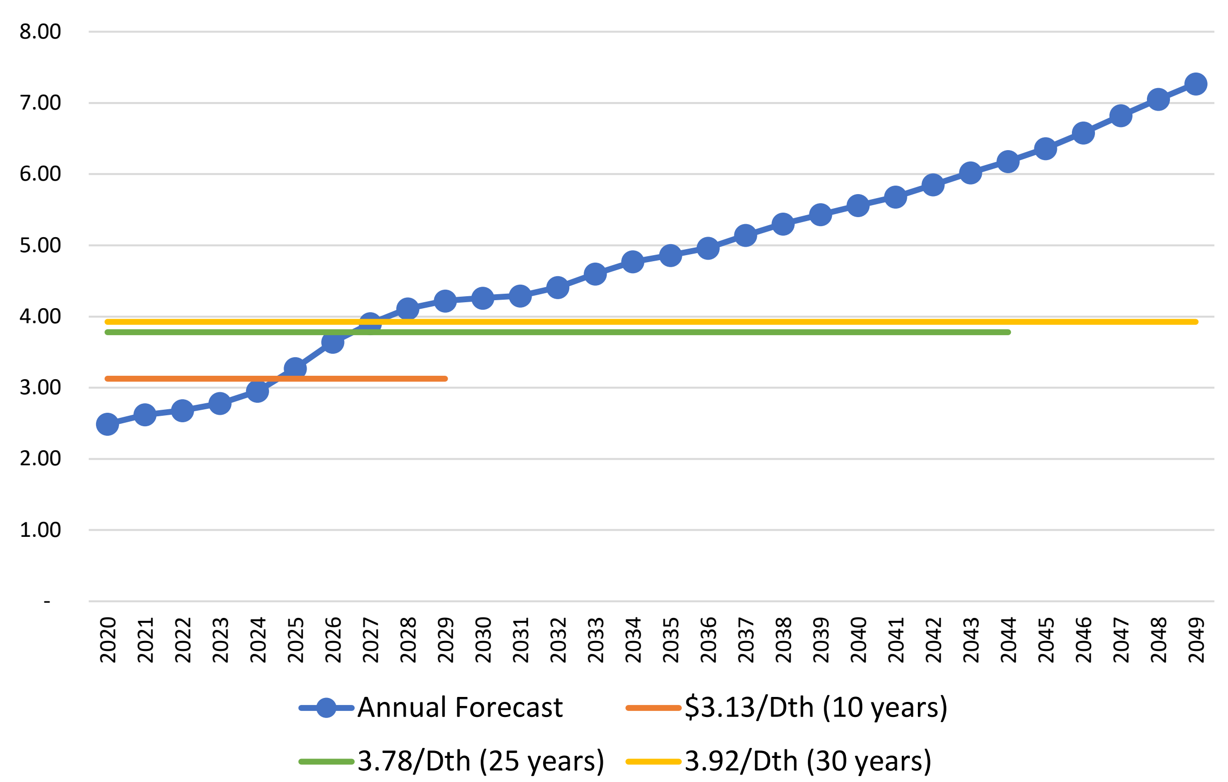
A. Avoided Cost of Energy

Q: WHAT ARE THE AVOIDED ENERGY BENEFITS OF A SOLAR PHOTOVOLTAIC (PV) PROJECT?

A: New solar generation will displace the marginal source of electric energy on the Dominion system. To calculate avoided energy costs, DESC Witness Everett's testimony appears to use Dominion's 10-year levelized energy prices by time-of-use (TOU) period that are included in its standard offer Power Purchase Agreement tariff (PR-1). These avoided energy costs should be extended to the

25-year economic life of a solar system. To estimate avoided energy costs over a 25-year horizon, I started with DESC's 10-year levelized PR-1 energy prices, then escalated these ten-year levelized energy prices based on the increase in levelized natural gas prices over a 25-year forecast period versus a 10-year period. With gas-fired generation expected to be the predominant marginal resource on the DESC system in the future, it is reasonable to expect that marginal energy costs will escalate with natural gas costs over time. For this step, I used the Energy Information Administration's (EIA) *2020 Annual Energy Outlook* (AEO) forecast of natural gas prices at the Henry Hub, Louisiana. **Figure 1** below shows that gas price forecast, as well as the levelized prices over various terms. The 25-year levelized price represents a 21% percent increase over the 10-year levelized price, assuming an 8.5% discount rate corresponding to DESC's weighted average cost of capital.

Figure 1: *2020 AEO Forecast Natural Gas Price*



Applying these increases in levelized natural gas prices to Schedule PR-1 prices results in the avoided energy rates shown in **Table 2** below. **Table 1** shows the Schedule PR-1 energy prices from which I started. These are the avoided energy benefits that a solar project can provide, expressed on a TOU basis.

Table 1: Schedule PR-1 Energy Credits for a 10-year Period ($/kWh)

TOU Period	June-September	October-May
On Peak	$0.03105	0.03252
Off Peak	$0.02751	0.02893

Table 2: Escalated Energy Credits for a 25-year Period ($/kWh)

TOU Period	June-September	October-May
On Peak	$0.03754	0.03931
Off Peak	$0.03326	0.03487

Q: **HAVE YOU ESTIMATED AN AVERAGE 25-YEAR LEVELIZED PRICE FOR THE AVOIDED ENERGY BENEFITS OF SOLAR PV?**

A: Yes. Based on DESC's TOU periods[1] and estimated annual solar output by TOU period,[2] I computed the following weighted average prices for a typical solar PV project:

Table 3: Annual Average Solar PV Energy Credits $/kWh)

Term	Avoided Energy Benefit
10 years (2020-2029)	0.03056
25 years (2020-2044)	0.03694

[1] The peak period for DESC is Hour Ending (HE) 11-22 in May to October, and HE 7-13 & 18-22 in November to April.

[2] I estimate solar output using the National Renewable Energy Lab's PVWATTS tool. I assumed the default PV Watts settings for a rooftop PV system in Charleston, SC. These include a 4.0 kW-DC system size, fixed 20-degree tilt, south-facing orientation, and a 1.2 DC to AC inverter loading ratio.

Q: DO YOU BELIEVE THESE ARE REASONABLE AVOIDED ENERGY BENEFITS?

A: Yes. Dividing the solar weighted average energy price (0.0306 $/kWh over ten years), net of variable O&M, by the 2020 AEO forecast price of natural gas ($3.13 per Dth), adjusted for transportation, results in a market heat rate of about 6,500 Btu/kWh.[3] This is not an unreasonable assumption if solar displaces conventional natural gas-fired generation from an efficient Combined Cycle Gas Turbine (CCGT) in most hours. This relatively low market heat rate may reflect some hours when non-gas resources with lower variable costs than a CCGT are on the margin.

B. Avoided Generation Capacity

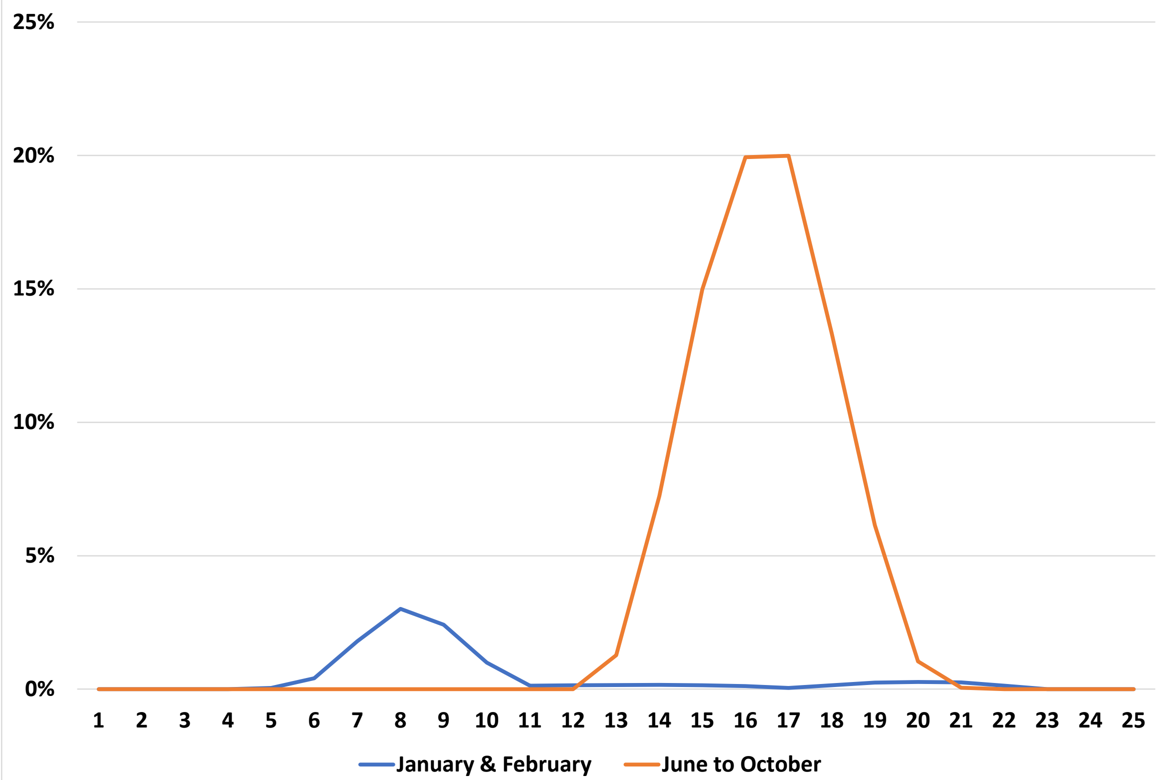
Q: WHAT ISSUES HAVE YOU IDENTIFIED WITH DESC'S STATED AVOIDED GENERATION CAPACITY COSTS FOR A SOLAR PV PROJECT?

A: The most significant issue is the capacity contribution of solar to avoiding DESC's need for generation capacity. To estimate solar's capacity contribution in the recent past, I looked at five years of hourly DESC loads, from 2015 to 2019, as reported to FERC in Form 714, and developed a Peak Capacity Allocation Factor (PCAF) for each hour of the year, based on the extent to which hourly load exceeds 90% of the annual peak hour's load. Due to the potential for both summer and winter peaks, it is important to look at a five-year period to capture the relative frequency of these seasonal peaks. This results in probability weights in each hour and month of the year that are concentrated on afternoon hours in summer months and on morning hours in January, as shown in **Figure**

[3] Assuming variable O&M equal to $0.00255 per kWh, from Table 2 of EIA's February 2020 report on capital cost benchmarks (at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf), and gas transportation cost of $1.20 per MMBtu, this calculation is ($30.60/MWh - $2.55/MWh) x 1000 / ($3.13/Dth + $1.20/Dth) = 6,472 Btu/kWh.

2 below. The smaller allocation of generation PCAFs to the winter reflects the shorter and less frequent utility peaks during winter cold snaps.

Figure 2: *Average 2015-2019 Generation PCAFs*



Applying a solar profile to the PCAF distribution results in a solar PV capacity contribution of 34%. Thus, I assume that 34% of a solar PV project's capacity may be assumed to contribute to meeting DESC's capacity needs in its peak load hours.

Q: WHAT ARE DESC'S AVOIDED GENERATION CAPACITY COSTS?

A: The approach that I used to calculate the DESC's long-run avoided capacity costs for generation is based on the cost of a new combustion turbine (CT), as the marginal source of capacity. Various sources exist to estimate this cost. DESC's 2020 Integrated Resource Plan (IRP) indicates that the capital cost of a new CT is $918 per kW.[4] Alternatively, the EIA's report on capacity cost benchmarks,

[4] See the table at page 39 of the DESC 2020 IRP.

referenced in footnote 3 above, indicates a CT capital cost in the range of $713 per kW (for 237 MW from a 1 x GE 7FA) to $1,150 per kW (for 105 MW from 2 x LM6000 units), with an average of $944 per kW.

In the calculation below, I have used the DESC IRP CT capital cost of $918 per kW; this CT unit is in all of the utility's resource plan scenarios.[5] The following **Table 4** shows that, after using a real economic carrying charge (RECC) factor to annualize the capital cost, adding a 14% reserve margin, applying the 34% capacity contribution for solar PV, and dividing by expected annual solar output, the avoided generation capacity cost for a solar PV project is $0.01351 per kWh. This can be compared to the current Schedule PR-1 capacity credit of $0.00379 per kWh. However, when the current credit is adjusted upward for my recommended 34% solar capacity contribution, rather than the 11% solar capacity contribution adopted in amended QF Order No. 2019-847, the result is a similar avoided cost capacity value of about $0.012 per kWh.

Table 4: Avoided Generation Capacity Costs

line	**Component**	**Value**	***Notes***
A	CT Cost ($ per kW)	918	*Based on DESC IRP*
B	RECC Annualization Factor	7.4%	*Calculated RECC*
C	Annual Cost of New Capacity ($/kW-year)	67.93	*A x B*
D	Plus 14% Reserve Margin ($/kW-year)	77.44	*IRP Summer PRM*
E	Solar Capacity Contribution	34%	*PCAF Analysis*
F	Avoided Generation Capacity ($/kW-year)	23.10	*D x E*
G	Solar Annual Output (kWh per kW)	1,709	*PVWATTS Charleston*
H	Avoided Generation Capacity ($/kWh)	0.01351	*F / G*

C. Avoided Energy and Capacity Losses

Q: DO YOU AGREE WITH DESC WITNESS EVERETT THAT THE POWER EXPORTED FROM DISTRIBUTED SOLAR FACILITIES DOES NOT AVOID DISTRIBUTION LINE LOSSES?[6]

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[5] DESC 2020 IRP, at pp. 40-41.

[6] See DESC Testimony (Everett), at pp. 16-17.

A: No, I do not. Assuming that the penetration of distributed solar is low, as it is in South Carolina today, the power exported from a small customer-owned solar system on the distribution system will be consumed by the solar customer's immediate neighbors. These exports will displace system power that otherwise would need to be delivered to the neighbors from remote utility-scale generation over the utility's entire upstream transmission and distribution facilities. The avoided system power for the neighbors would have been transmitted and distributed over virtually the same distance as the power that the solar customer avoids by serving its own load behind the meter. As a result, the avoided line losses associated with exports from distributed solar will be very similar to the avoided losses for the power consumed behind the solar customer's meter. In essence, because the exports from distributed solar move such a short distance over the distribution system before they are consumed by the neighbors, the avoided line losses will not be significantly different than the avoided losses from power consumed behind the meter.[7]

Q: PLEASE DISCUSS THE ENERGY AND CAPACITY LINE LOSSES THAT DISTRIBUTED SOLAR WILL AVOID.

A: The avoided energy and capacity costs calculated above are at the generation level. A solar PV project located behind a customer's meter avoids marginal line losses on both the DESC transmission and distribution systems for its entire output. Thus, based on DESC's marginal energy and capacity losses, I have calculated the following avoided line losses.[8]

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[7] This situation will change only if the penetration of distributed solar grows to the point that distributed solar output exceeds the midday minimum load on many distribution circuits, such that solar exports backfeed up these circuits to the nearest distribution substation. This issue has become significant only in a market such as Hawaii, where solar penetration has reached about 20% of residential customers. This is far higher than the current residential solar penetration in South Carolina.

[8] Provided in response to Question 16a of the first data request of Vote Solar, *et al*. to DESC.

Table 5: Avoided Line Losses

Component	%	$/kWh
Avoided Energy Losses	8%	0.00204
Avoided Capacity Losses	15%	0.00305
Total Avoided Losses		0.00493

D. Avoided transmission and distribution capacity

Q: DESC WITNESS EVERETT DOES NOT ADDRESS THE ISSUE OF AVOIDED TRANSMISSION AND DISTRIBUTION (T&D) CAPACITY COSTS ON THE DESC SYSTEM. DOES A SOLAR PV PROJECT AVOID T&D CAPACITY COSTS?

A: Yes. Because a solar PV project's output will serve much of a customer's on-site load, without ever flowing onto the grid, DESC may expect to see reduced loads on its T&D system. The remaining power that is be exported to the grid is likely to be substantially consumed by neighboring distribution loads, thus unloading the upstream DESC transmission and distribution systems.

Q: HOW DID YOU DETERMINE THE CONTRIBUTION OF SOLAR OUTPUT TO AVOIDED TRANSMISSION AND DISTRIBUTION SYSTEM CAPACITY COSTS?

A: Solar avoids transmission and distribution (T&D) investments by reducing peak loads on the DESC T&D system. Similar to my Peak Capacity Allocation Factor (PCAF) analysis for generation capacity contributions from solar PV, I performed PCAF analyses based on transmission system and distribution system hourly loads provided by DESC. This load data includes hourly loads at each DESC transmission and distribution substation.[9] Compared to my PCAF analysis of the solar contribution to generation capacity (which was based on

[9] The inputs to the PCAF analyses I performed for transmission and distribution were, respectively, DESC's hourly transmission bank and distribution substation loads. I calculated a weighted average transmission PCAF by weighting the PCAF allocations for each transmission bank by its maximum load; similarly, the distribution PCAF allocation weighted the PCAF allocations for each distribution substation according to DESC-indicated capacity of each distribution substation.

system load data), the T&D PCAF analyses show similar, but modestly higher, solar capacity contributions of 43% for transmission and 36% for distribution.

To estimate the marginal cost of T&D capacity, I have used the well-accepted National Economic Research Associates (NERA) regression method. This approach is used by many utilities to determine their marginal transmission and distribution capacity costs that vary with changes in load. The NERA regression model fits incremental T&D investment costs to peak load growth. The slope of the resulting regression line provides an estimate of the marginal cost of T&D investments associated with changes in peak demand.[10] To capture long-run marginal costs, the NERA methodology typically uses at least 15 years of data on T&D investments and peak transmission system loads. This data is historical data reported in FERC Form 1, plus a current forecast of future investments and expected load growth if available. I have utilized NERA regressions based on DESC's historical peak load growth and transmission and distribution investments over the period from 2009 to 2025, using DESC's FERC Form 1 data for the historical portion of this period through 2019, as well as a six-year forecast of T&D investments and load growth (2020-2025). I add loaders for the operations and maintenance (O&M) and administration and general (A&G) costs associated with these investments in T&D rate base. These loaders are based on Form 1 data on T&D O&M and A&G costs as percentages of rate base investments.

The testimony of Brian Horii for the Office of Regulatory Staff (ORS) observes that these regressions based on coincident peak demand overstate marginal T&D costs, because the sum of the noncoincident peak loads on the elements of the T&D system that drive investments are higher than the coincident system peak loads used in the denominator of marginal T&D costs.[11] I agree that

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[10] It is important to keep in mind that peak load growth is a proxy for growth in T&D capacity. Some utilities – for example, Southern California Edison – track their T&D system capacity over time and use this data directly in the regression.

[11] See direct testimony of Brian Horii on behalf of the South Carolina Office of Regulatory Staff, at pages 29-30.

this observation has merit, particularly given that my PCAF analysis also looks at a range of hours with loads within 10% of the peak hour, and not just at the peak hour. Accordingly, I have included 27% and 23% downward adjustments to the avoided transmission and distribution capacity costs, respectively, to recognize that marginal T&D costs per unit of noncoincident peak loads on the T&D systems are lower than the marginal T&D costs per unit of coincident system peak loads. DESC's distribution load data indicates that the coincident system peak load is 23% lower than the sum of noncoincident peak distribution substation loads. Similarly, the coincident peak load on the transmission system is 27% lower than the sum of non-coincident transmission bank peak loads.

My analysis results in dollars per kW values for avoided T&D capacity, which I annualize using a RECC factor. I then multiply these annualized values by the PCAF-based solar contribution to avoiding T&D capacity. Finally, to express this avoided transmission cost on the basis of dollars per MWh of solar output, I divide by the expected annual output of distributed solar PV, in kWh per kW. The final step I perform is to assume these costs will increase with inflation and to levelize them over 25 years at an 8.5% discount rate. The following **Tables 6 and 7** show the results of my calculation of the DESC avoided T&D capacity costs.

Table 6: Avoided Transmission Capacity Costs

Line	**Component**	**Value**	***Notes***
A	Avoided Transmission Capacity ($/kW-year)	63.56	*NERA method*
B	Solar Capacity Contribution	42.5%	*PCAF method*
C	Solar Annual Output (kWh per kW)	1,709	*From PVWATTS*
D	Avoided Transmission Capacity ($/kWh)	0.01581	*A x B / C*
E	Adjusted for 25-year Levelized Value	0.01861	*D x 1.18*

Table 7: Avoided Distribution Capacity Costs

Line	**Component**	**Value**	***Notes***
A	Avoided Distribution Capacity ($/kW-year)	92.57	*NERA method*
B	Solar Capacity Contribution	35.6%	*PCAF method*
C	Solar Annual Output (kWh per kW)	1,709	*From PVWATTS*
D	Avoided Transmission Capacity ($/kWh)	0.01928	*A x B / C*
E	Adjusted for 25-year Levelized Value	0.02270	*D x 1.18*

The sum of these avoided transmission and distribution costs is $0.04131 per kWh.

E. Fuel Hedge Benefits

Q: DESC WITNESS EVERETT DOES NOT DISCUSS OR INCLUDE A FUEL HEDGE BENEFIT. SHOULD SUCH A BENEFIT BE INCLUDED?

A: Yes. Renewable generation, such as solar PV, reduces a utility's use of natural gas, and thus decreases the exposure of ratepayers to the volatility and periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 3** below.

Renewable generation provides a long-term hedge against volatile fuel costs for the entire 25-year economic life of, for example, a solar unit. As discussed in my opening testimony, calculations of this component underestimate this benefit by focusing on the costs of existing utility hedging programs. These programs only reduce the volatility in short-term fuel and purchased power expenses for the next one to three years. In contrast, there are substantial financial costs to establish a long-term hedge equivalent to what renewable generation provides.

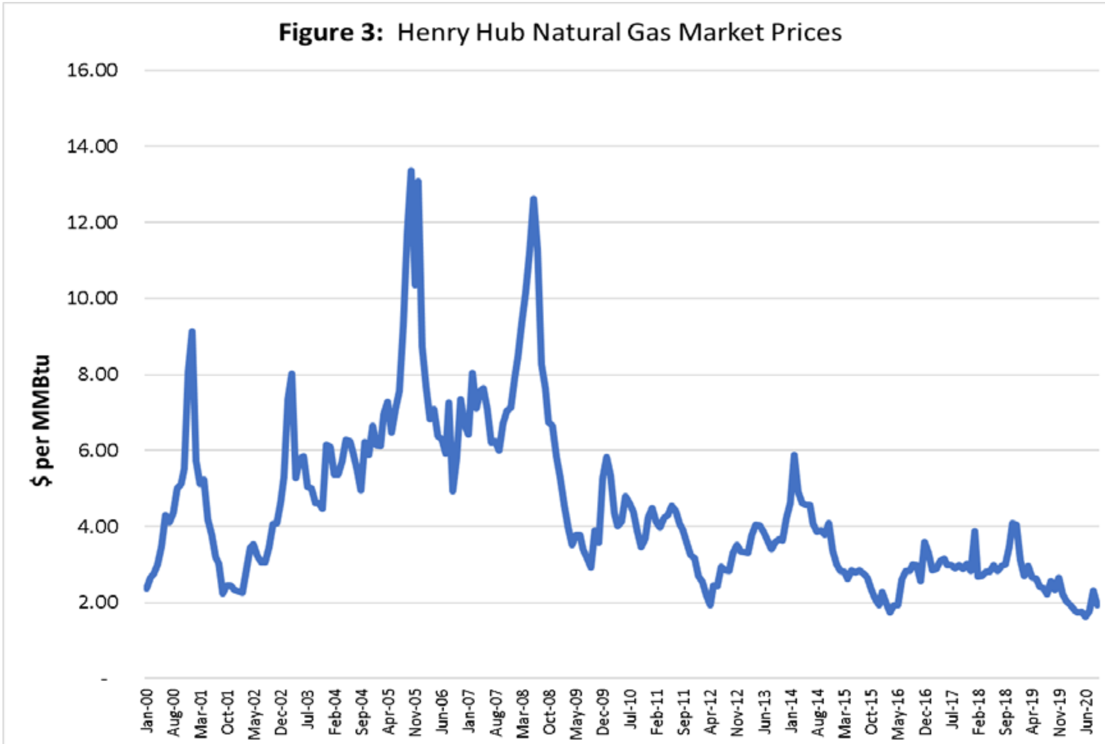

Figure 3: Henry Hub Natural Gas Market Prices

Q: HOW WOULD YOU CALCULATE THE FUEL HEDGE BENEFIT?

A: To calculate this benefit, I follow the methodology used in the *Maine Distributed Solar Valuation Study (Maine Study)*, a 2015 study commissioned by the Maine Public Utilities Commission and authored by Clean Power Research.[12] This approach recognizes that one could contract for future natural gas supplies today, and then set aside in risk-free investments the money needed to buy that gas in the future. This would eliminate the uncertainty in future gas costs. The additional cost of this approach compared to purchasing gas on a "pay as you go" basis (and using the money saved for alternative investments) is the benefit of reducing the uncertainty in the costs for the fuel that solar PV displaces.

I have performed this calculation for DESC, using my base gas cost forecast (the EIA *AEO 2020* forecast), U.S. Treasuries (at current yields) as the risk-free

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[12] See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015). Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

investments, and a marginal heat rate of 6,500 Btu per kWh. The result is a value of $0.033 per kWh as the 25-year levelized benefit of reducing fuel price uncertainty. Short-term hedge transactions do not capture this long-term fuel hedge value, given that short-run price volatility (i.e. in the next 12-months or next 3-5 years) is not the same as price volatility over a 25-year period. For example, highly liquid futures markets do not exist over a 25-year timeframe, because of the significant costs and risks involved. Instead, ratepayers bear these risks and costs over the life of a fossil-fueled resource whose fuel costs are volatile, because ratepayers ultimately "pay as you go" at the prevailing market price for fuel. Renewable generation provides a significant benefit to ratepayers by eliminating the risks of this volatility.

F. Avoided GHG Emission Benefits

Q: DESC WITNESS EVERETT DOES NOT INCLUDE A BENEFIT ASSOCIATED WITH AVOIDED COSTS TO REDUCE GREENHOUSE GAS (GHG) EMISSIONS. PLEASE COMMENT.

A: My opening testimony argues that the IRPs of the South Carolina utilities, including DESC, show that reducing future carbon emissions is a significant driver of those plans and that the utilities are planning and spending money today to reduce their carbon emissions.[13] Therefore, the benefit associated with reducing carbon emissions should not be assumed to be zero.

Q: HAVE YOU CALCULATED THIS BENEFIT?

A: Yes. DESC's 2020 IRP assumes carbon costs of $25 per MT for compliance with future GHG regulations.[14] I assumed this cost increases with inflation at 2% per year. Using the conversion factor that burning an MMBtu of natural gas produces 117 pounds of carbon dioxide, DESC's IRP assumption for GHG compliance costs is equivalent to approximately a $1.50 per MMBtu adder to the cost of natural gas. Assuming a 6,500 Btu/kWh marginal system heat rate, this

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[13] See pages 26-29 of DESC's 2020 IRP.
[14] DESC 2020 IRP, at p. 44.

component becomes $0.00951 per kWh in 2020, or $0.01124 per kWh on a 25-year levelized basis.

G. Summary of Benefits

Q: PLEASE SUMMARIZE THE AVOIDED COST BENEFITS FOR SOLAR PV PROJECTS ON THE DESC SYSTEM.

A: This summary is provided in **Table 8**, below.

Table 8: Summary of Avoided Cost Benefits

Avoided Cost Component	Value *(25-year levelized $ per kWh)*
Energy	0.0383
Generation capacity	0.0135
Line losses	0.0049
Transmission capacity	0.0186
Distribution capacity	0.0227
Fuel Hedge	0.0335
GHG Compliance Costs	0.0112
Total	**0.1428**

H. Bill Savings

Q: HAVE YOU ANALYZED RESIDENTIAL CUSTOMER BILL SAVINGS ON THE DESC SYSTEM?

A: Yes. These savings are the primary benefit of solar for participating customers, and thus are used in the Participant Cost Test. Bill savings also are the lost revenues for the utility when a customer adopts solar, and thus are the principal cost in the RIM test.

I modeled residential bill savings for DESC's standard tiered rates for residential service. Assuming a residential customer with an annual load of 12,000 kWh per year, and a solar system sized to serve 75% of that load (i.e., solar output of 9,000 kWh per year), I estimate monthly pre-solar costs of about $125 per month, dropping to monthly post-solar costs of $41 per month, for bill savings of $84 per month on the tiered rate. The portion of overall bill savings related to the portion of solar output that is exported to the grid should be the focus of a NEM cost-benefit analysis, given that customers have rights under federal law (PURPA) to serve their own load and Act 62 specifically states that the solar choice tariff should not penalize behind-the-meter use of customer-generation.

To determine a long-term levelized value for bill savings from exported power, I escalate the savings with inflation over a 25-year period, including the effect of solar degradation over time,[15] then levelize the savings at an 8.5% discount rate. These bill savings for exported power are summarized in the final line of the following **Table 9**, in terms of dollars per year, per month, and per kWh of solar exports.

Table 9: Dominion Residential Customer Solar Bill Savings on Tiered Rate

	$ / year	$ / month	kWh	$ / kWh
Pre-solar Bill	$1,503	$125	12,000	0.125
Post-solar Bill	$492	$41	3,000	0.164
Bill Savings – total	$1,011	$84	9,000	0.112
Delivered / imports	$514	$43	4,388	0.117
Exports	$496	$41	4,612	0.108
25-year Levelized Exports	$561	$47	4,433	**0.127**

I. Solar Costs

Q: DESC WITNESS EVERETT PRESENTS A CALCULATION OF RESIDENTIAL SOLAR COSTS, INCLUDING OFFSETS FOR FEDERAL AND STATE TAX CREDITS. DESC WITNESS SCOTT ROBINSON ALSO DISCUSSES THE ASSUMPTIONS FOR SOLAR COSTS USED IN HIS ADOPTION MODEL. PLEASE DISCUSS YOUR VIEW ON THE COSTS FOR CUSTOMERS WHO ADOPT SOLAR.

A: There is clearly a range of customer costs for residential and small commercial solar, based primarily on a range of capital costs in the market and whether a customer pays cash, finances the system, or signs a solar lease. I have used a

[15] The assumed degradation rate is 0.5% per year, which is a standard industry assumption also used by DESC (see DESC testimony [Robinson], at p. 5).

cash flow model for the levelized cost of energy (LCOE) for solar. My LCOE model uses capital costs for residential solar that are based on recent reported system costs in South Carolina.[16] The primary assumptions in my model are shown below in **Table 10.**

Table 10: Key Assumptions for the Levelized Cost of Residential Solar

Assumption	Value
Median Solar Cost	$3.10 per watt DC in 2020
Federal ITC	26% in 2020
State tax credit	25% capped at $3,500
Financing Cost	6%
Participant discount rate	5%
Financing Term	20 years
Inverter Replacement	$150 per kW-DC in Year 15
Maintenance Cost	$20 per kW-DC per year

The residential solar LCOEs that I have developed are 9.4 cents per kWh for cash purchases and 11.5 cents per kWh for loan-financed systems.[17] I use the latter value in my SPM tests.

J. Integration Costs

Q: HAS THE COMMISSION ADOPTED A COST TO INTEGRATE SOLAR INTO THE DESC SYSTEM?

A: Yes, it has. The avoided energy costs adopted for QFs in Order No. 2020-224 in Docket No. 2019-184-E include an interim Variable and Embedded Integration Charge of $0.94 per MWh. Thus, solar integration costs are included as an offset to the avoided energy costs calculated above. In the cost-effectiveness tests

[16] From the Energy Sage website, https://news.energysage.com/how-much-does-the-average-solar-panel-installation-cost-in-the-u-s/.
[17] Costs for leased system may be higher than this range, because leased systems do not qualify for the 25% state tax credit.

provided below, I have removed the integration costs from the avoided energy costs (on the benefit side of the tests) in order to show them as a distinct cost (on the cost side of the tests).

K. Societal Benefits

Q: DESC WITNESS EVERETT DOES NOT DISCUSS OR ATTEMPT TO QUANTIFY THE SOCIETAL BENEFITS OF SOLAR DERS THAT WOULD ACCRUE TO THE CITIZENS OF SOUTH CAROLINA. HAVE YOU QUANTIFIED SUCH BENEFITS, OR ARE YOU AWARE OF OTHERS WHO HAVE?

A: Yes. New renewable generation will supply a number of environmental and public policy benefits for DESC ratepayers and the citizens of South Carolina. These include:

- **Health benefits of reduced emissions of criteria pollutants.** Exposure to criteria air pollutants, including particulate matter, sulfur dioxide, and nitrogen oxides causes asthma and other respiratory illnesses, cancer, and premature death. Models and analyses from the U.S. Environmental Protection Agency (USEPA) can be used to quantify the health benefits of reducing these emissions from fossil fueled generation. ORS witness Mr. Horii cites a USEPA study that calculates benefits of $17 to $44 per MWh (in 2020 dollars) for solar generation that reduces criteria air emissions in the Southeast.[18]
- **Reduced methane leakage** is an additional environmental benefit of displacing natural gas use. It is a significant benefit because methane has about 100 times the greenhouse warming potential of carbon dioxide in the 20 years after it leaks to the atmosphere. Based on recent research estimating 1.9% leakage upstream of gas-fired power plants,[19] methane leakage significantly increases the carbon-equivalent emissions of gas-fired power plants, by almost 70%. As a result, it is important to account for these directly-related methane emissions from the production and pipeline

[18] ORS testimony (Horii), at p. 33.

[19] *See* Alvarez, Ramón A., *et al.* "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain," *Science*, Vol. 361, No. 6398, 13 July 2018. Other research has determined that throughput on natural gas pipeline systems and methane leakage are highly correlated; thus, it is reasonable to assume that decreased throughput would result in decreased leakage. *See* He, Liyin, *et al.* "Atmospheric Methane Emissions Correlate With Natural Gas Consumption From Residential and Commercial Sectors in Los Angeles," *Geophysical Research Letters*, Vol. 46, No. 14, 2019, at pp. 8563–8571.

infrastructure that would serve the gas-fired generation displaced by new solar generation. I calculate that the benefit of avoided methane leakage on the DESC system is $7.80 per MWh, based on avoiding the methane leakage associated with the marginal use of natural gas in power plants.

- **Additional benefits of reduced carbon emissions.** The societal damages from climate change have been quantified as the "social cost of carbon" (SCC). A recent estimate of the SCC for the U.S. is the median estimate of $417 per metric tonne from an academic review of a range of SCC values published in October 2018 in *Nature Climate Change*.[20] The SCC significantly exceeds estimates of the direct, compliance costs of controlling carbon emissions (such as the $25 per ton compliance cost assumed in the DESC IRP). Reducing carbon dioxide and methane emissions will have the additional social and economic benefit of avoiding these damages from climate change. This societal benefit can be measured as the SCC minus DESC's assumed carbon compliance costs, which results in a 25-year levelized benefit of $133 per MWh.
- **Land use benefits.** Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station solar plants require larger single parcels of land, and are more remotely located where the land has other uses for agriculture or grazing. Today, the land typically must be removed from this prior use when it becomes a solar farm. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year. The lost value of the land depends on the alternative use to which it could be put. The U.S. Department of Agriculture has reported the average value of agricultural land in South Carolina in 2019 as $3,400 per acre.[21] Assuming 3.9 acres per GWh per year, a $3,400 per acre value of land, and a 25-year loan at an interest rate of 5% per year to finance the land purchase, distributed solar provides a land use benefit of about $1 per MWh of solar output.

The societal benefits enumerated above total $172 per MWh, using the midpoint of the range of health benefits. This calculation does not include the direct and indirect economic impacts of net metered distributed generation to South Carolina set forth in Dr. Hefner's direct testimony.

[20] See Ricke et al., "Country-level social cost of carbon," *Nature Climate Change* (October 2018). Available at: https://www.nature.com/articles/s41558-018-0282-y.epdf.
[21] See https://downloads.usda.library.cornell.edu/usda-esmis/files/pn89d6567/g732dn07g/9306t9701/land0819.pdf.

Q: ARE THERE OTHER SOCIETAL BENEFITS FROM DISTRIBUTED SOLAR THAT ARE DIFFICULT TO QUANTIFY?

A: Yes. There are additional benefits of distributed solar resources that are difficult to quantify, but that the Commission should acknowledge and consider qualitatively. These additional benefits include:

- Rooftop solar enhances the **reliability and resiliency** of customers' electric service, because solar DG is a foundational element for backup power systems and micro-grids that can provide uninterrupted power when the utility grid is down.
- Distributed solar also enhances customers' **freedom, choice, and engagement** – allowing them to choose the source of their electricity and to produce much of it themselves on their private property. This results in customers who are more engaged and better informed about how their electricity is supplied.
- The choice of using private capital to install solar DG on a customer's premises leverages **a new source of capital** to expand South Carolina's clean energy infrastructure and allows the state to take full advantage of federal tax incentives for solar that have begun to phase out this year.

L. Cost Effectiveness

Q: HOW DO YOU PROPOSE EVALUATING SOLAR PV COST-EFFECTIVENESS?

A: As explained in my direct testimony, it is vital to examine the benefits and costs of distributed resources from multiple perspectives of each of the major stakeholders – the utility system as a whole, participating NEM/DER customers, and other ratepayers – so that the regulator can balance all of these important interests. Thus, the Commission should consider the results of the full suite of standard practice manual (SPM) tests for cost-effectiveness. I have assembled the benefits and costs of distributed solar discussed above into the five primary SPM tests. The following **Figure 4** and **Table 11** show the results for the five SPM tests on the DESC system.

Figure 4: *Summary of SPM Test Results*

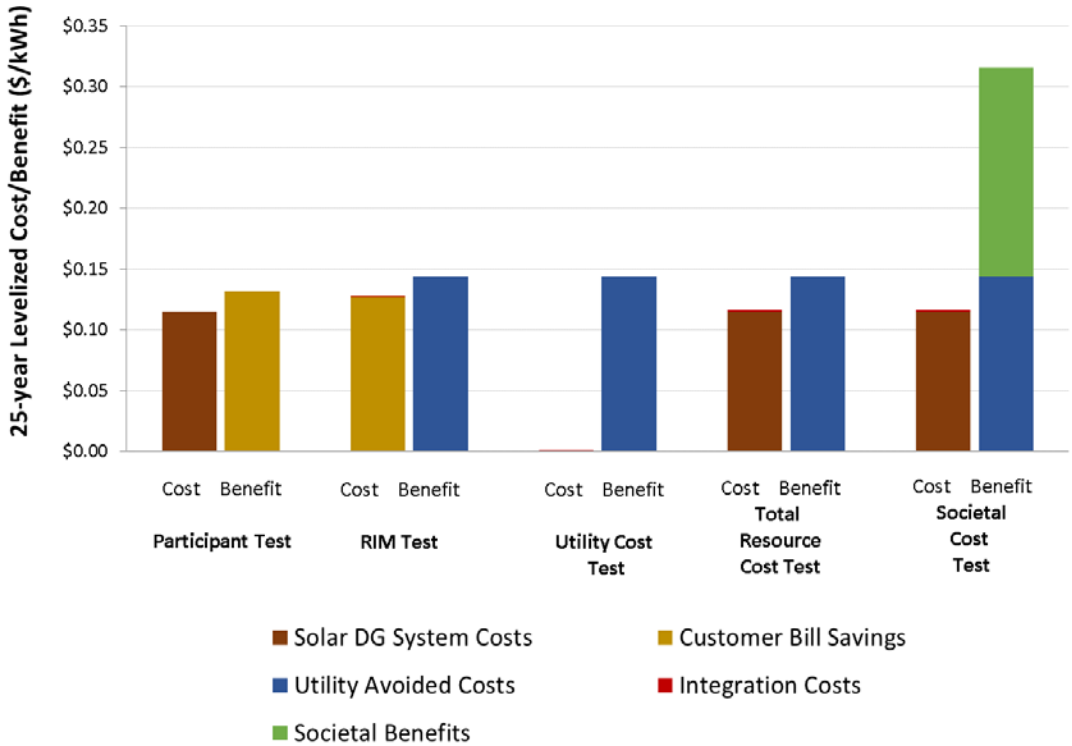

Table 11: Benefits and Costs of Solar DG for DESC (25-yr levelized $/kWh)

Benefit-Cost SPM Test	**Participant**		**RIM / UCT**		**Total Resource**		**Societal**	
Category	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Direct Avoided Costs				0.144		0.144		0.144
Lost Revenues / Bill Savings		0.132 (all solar)	0.127 (exports)					
Integration			0.001		0.001		0.001	
Solar DG LCOE	0.115				0.115		0.115	
Societal Benefits								0.172
Totals	0.115	0.132	0.128	0.144	0.116	0.144	0.116	0.316
Benefit / Cost Ratios	**1.15**		**1.12 (RIM) >>1.00 (UCT)**		**1.24**		**2.72**	

Q: WHAT DO YOU CONCLUDE FROM THESE RESULTS?

A: The results show that distributed residential solar on the DESC system passes all of the SPM tests. As a result, my principal conclusions are the following:

1. Solar DG is a cost-effective resource for DESC, as the benefits equal or exceed the costs in the TRC, Utility Cost, and Societal tests. As a result, in the long-run, deployment of solar DG will reduce the utility's cost of service.

2. Net metering does not cause a cost shift to non-participating ratepayers, including low-income customers, as shown by the results for the Ratepayer Impact Measure and Utility Cost tests.

3. Modifications to net metering are not needed to recover the utility's full cost of service over time from net metering customers. Major rate design changes for residential DG customers, such as increased fixed charges, the use of demand charges, or two-channel billing to set different compensation rates for imported and exported power, are not needed to recover the utility's full cost of service over time from net metering customers.

4. The economics of solar DG are marginal for DESC's residential customers, as shown by the Participant test results just above 1.0 and the modest amount of solar adoption to date. Thus, continuing the current compensation provided to solar DG customers could be important in maintaining the growth of this resource, particularly given the ongoing step-down in the federal tax credit.

5. There are significant, quantifiable societal benefits from solar DG, including public health improvements from reduced air pollution and from mitigating the damages from carbon emissions.

6. Solar DG also provides other important benefits that are difficult to quantify. These include the enhanced reliability and resiliency of customers' electric service, enhanced customer freedom, new sources of private capital to expand South Carolina's clean energy infrastructure, and an opportunity for the state's citizens to take advantage of federal tax incentives for solar.

IV. RESPONSE TO THE OFFICE OF REGULATORY STAFF

A. Cost-of-Service Issues

Q: ORS WITNESS BRIAN HORII EXPRESSES A CONCERN THAT THE DUKE ENERGY COST-OF-SERVICE STUDY FOR NEM CUSTOMERS USES A SUMMER 1 COINCIDENT PEAK ("1 CP") AS THE DEMAND METRIC. HE IS CONCERNED THAT THIS METRIC IS INACCURATE GIVEN THE RECENT WINTER PEAKS THAT DUKE HAS EXPERIENCED.[22] PLEASE COMMENT.

[22] ORS Testimony (Horii), at pp. 18-19.

A: ORS Witness Horii answers his own concern a few pages earlier in his testimony, where he clearly and correctly explains that both marginal and embedded cost-of-service (COS) analyses have roles to play in evaluating the reasonableness of a NEM tariff. Indeed, Act 62 explicitly calls for both to be considered in the design of the Solar Choice tariffs. He observes that an embedded cost-of-service analysis is important for "evaluating the policy issue of whether the solar customers would be paying their fair share of costs."[23] I agree that the essential purpose of a cost-of-service analysis, as performed in periodic rate cases, is to devise a fair allocation of the utility's costs among its customer classes. These costs are mostly historic costs incurred in the past, and therefore the allocators used to assign them to customer classes often will consider the demand drivers that caused them to be incurred in the past. From this perspective, Duke's use of the Summer 1 CP allocator is reasonable, as Duke historically has been predominantly a summer-peaking utility, with the winter peaks emerging only in a few recent cold snaps. That said, I agree with ORS Witness Horii that marginal cost information also is important to the design of the rates in the Solar Choice tariff, especially given that the marginal cost data is forward-looking, is more granular in time than the allocators in an embedded COS study, and focuses on the impact of a customer's choice on the margin to use and export on-site solar generation. I anticipate that, as the design of tariffs for small customers becomes more sophisticated – for example, by introducing various types of time-dependent pricing – the use of more granular marginal cost considerations will increase in importance. Act 62 clearly expects that there is a balance between the embedded and marginal COS perspectives that needs to be achieved in the Solar Choice tariff.

Q: WOULD THIS DOCKET BE THE APPROPRIATE PLACE TO MAKE CHANGES TO ONE OF THE ALLOCATORS IN DUKE'S EMBEDDED COST-OF-SERVICE STUDY?

[23] *Ibid.*, at p. 16.

A: No, it would not. A utility's embedded COS study is typically a major issue in general rate cases, where a broad range of parties have significant interests in how the utility's costs are allocated to its customer classes. Those rate cases are the correct venues in which all of the elements of an embedded COS study can be reviewed together, holistically, with all of the affected parties represented. The most recent rate cases for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) have approved embedded COS studies that include the Summer 1 CP allocator.[24]

B. Impacts on Low-Income Customers

Q: ORS WITNESS DR. JOHN RUOFF EXPRESSES CONCERN WITH THE IMPACTS ON LOW-INCOME CUSTOMERS OF ANY COST SHIFT FROM NET METERING CUSTOMERS TO NON-PARTICIPATING RATEPAYERS. PLEASE ADDRESS DR. RUOFF'S CONCERN.

A: Act 62 requires that the Solar Choice tariff should "eliminate any cost shift to the greatest extent practicable on customers who do not have customer sited generation."[25] With respect to DESC, the cost-effectiveness numbers presented in this rebuttal testimony indicate that there is presently no cost shift to non-participants under the current Act 236 policies and today's full retail net metering. This is demonstrated by net metering passing the Ratepayer Impact Measure (RIM) test for DESC residential customers. The RIM test is the most stringent test measuring impacts on non-participating ratepayers. Of course, the scope of this docket is limited to addressing the methodology for evaluating the Solar Choice tariffs. No actual Solar Choice tariffs have been proposed or evaluated, so it is premature to conclude whether there is a cost shift issue that needs to be addressed with those yet-to-be-filed tariffs.

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[24] For DEC, see Order No. 2019-323 in Docket No. 2018-319-E (May 21, 2019), at p. 32 (Finding of Fact 33). For DEP, see Order No. 2019-454 in Docket No. 2018-318-E (October 18, 2019), at p. 3, specifically approving the company's COS study "to allocate all revenues, expenses, and rate base items and to design rates for all customer classes…."
[25] See Section 58-40-20(G)(1).

It is also important to note that the solar net metering tariffs—by themselves—have little to no effect on the longstanding affordability issues raised by ORS Witness Ruoff, especially given the positive cost-effectiveness results discussed above and the relatively low penetration of distributed solar in South Carolina today. Utilities can and should take proactive steps to address affordability of essential utility service for their low-income customers, including adopting efficiency programs that serve low-income households, establishing programs that make the benefits of solar accessible for low-income customers, and offering affordable rate designs with arrearage management and discounts to standard tariff rates. Those steps will have a profound and direct role in making utility service affordable.

Q: DOES A SOLAR CHOICE TARIFF HAVE TO PASS THE RIM TEST FOR THE COMMISSION TO CONCLUDE THAT THERE IS NO COST SHIFT ISSUE?

A: No. My direct testimony discussed at length the issues with the RIM test, and why the Utility Cost Test is more appropriate for evaluating a new, forward-looking program such as the Solar Choice tariffs. Further, the cost shift issue is a matter of equity among groups of ratepayers, and there are multiple ways to address any inequities. For example, the utilities, the solar industry, the Commission, and the state of South Carolina can develop programs to increase the access of low-income customers to solar technology, thus allowing low-income ratepayers to become participating customers – not just non-participants. In other states, the solar industry is a strong supporter and partner in such programs to expand solar access.

In addition, any weighing of equities among groups of ratepayers also should consider the societal benefits of clean DER technologies. These benefits include health benefits from reductions in emissions of criteria air pollutants and mitigating the damages of climate change. These benefits can be of particular importance to disadvantaged, low-income communities who often bear greater burdens from environmental degradation in the past and present. Expanding access to solar that is built in and by these impacted communities is particularly important to address the environmental justice issues that this history raises.[26]

Q: DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A: Yes, it does.

[26] Act 62 includes specific provisions to encourage community solar programs that can expand access to solar in low- and moderate-income communities. See Section 58-41-40.

CERTIFICATE OF SERVICE

I hereby certify that the parties listed below have been served with a copy of the *Rebuttal Testimony of R. Thomas Beach* filed on behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Vote Solar, Solar Energy Industries Association, and the North Carolina Sustainable Energy Association by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

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This 29th day of October, 2020.

s/ Katherine Lee Mixson